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CHRISTIAN & BARTON, LLP
ATTORNEYS AT LAW

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DELAWARE P.S.C.

Michael J. Quinan
Direct Dial: 804.697.4149
Direct Fax: 804.697.6149
E-mail: mquinan@cblaw.com

August 15, 2013

VIA OVERNIGHT MAIL

Ms. Alisa Bentley, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, Delaware 19904

Re: In the Matter of the Application of Delmarva Power & Light Company for An Increase in Electric Base Rates and Miscellaneous Tariff Changes
Docket No. 13-115

Dear Ms. Bentley:

Enclosed please find an original and 10 copies of Direct Testimony of Nicholas Phillips, Jr. on behalf of the Delaware Energy Users Group to be filed in the above-referenced matter.

Please contact me should you have any questions regarding this filing. Thank you for your consideration.

Sincerely,

Michael J. Quinan

MJQ/wcv

Enclosures

cc: Service List *(via electronic mail)*

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DELAWARE P.S.C.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES AND MISCELLANEOUS TARIFF CHANGES (Filed March 22, 2013)	)	**Docket No. 13-115**

Direct Testimony and Exhibits of

Nicholas Phillips, Jr.

On behalf of

The Delaware Energy Users Group

August 16, 2013

BRUBAKER & ASSOCIATES, INC.

Project 9810

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES AND MISCELLANEOUS TARIFF CHANGES (Filed March 22, 2013)	**Docket No. 13-115**

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Direct Testimony of Nicholas Phillips, Jr.

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Direct Testimony of Nicholas Phillips, Jr.

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am testifying on behalf of The Delaware Energy Users Group ("DEUG"). DEUG represents large volume users of electric energy located in the service territory of Delmarva Power & Light Company ("Delmarva" or "Company").

I. INTRODUCTION AND SUMMARY

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A The purpose of my testimony is to address Delmarva's presented test year ending December 31, 2012 class cost of service study ("CCOSS"), explain how the study should be used, and recommend an appropriate class allocation and rate design of any authorized rate increase.

In order to make my testimony consistent with the revenue levels requested by Delmarva, I have in many instances used its requested numbers for revenues under proposed rates. However, use of those numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of rate change authorized for Delmarva in this proceeding.

Q **HOW IS YOUR TESTIMONY ORGANIZED?**

A First, I present an overview of cost of service principles and concepts. This is followed by a discussion of the typical classification and allocation of distribution related costs. Next, I present the results of a properly developed cost of service analysis for Delmarva that takes into account cost causation principles. This cost study indicates how individual customer class revenues compare to the costs incurred in providing distribution service to them. This analysis and interpretation is then followed by recommendations with respect to the allocation and rate design of class revenues with class costs.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.**

A My specific recommendations and conclusions are as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level and design of rates charged to customers.

2. Delmarva's CCOSS comports with generally accepted cost of service study methods. However, the classification and allocation of certain distribution plant accounts in Delmarva's CCOSS should be modified to classify a portion of those costs as customer-related.

3. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments must be made to connect a customer to the system. Therefore, these investments are considered customer-related.

4. Updating Delmarva's CCOSS to reflect a reasonable customer component in the classification and allocation of certain distribution plant costs shows that at current rates, the rates associated with the General Service Secondary and General Service Primary rate classes are above cost of service.

5. The results of the revised CCOSS, which takes into account actual cost utilization principles, should be used to allocate any distribution revenue increase in this proceeding as well as the design of distribution rates. The revised CCOSS supports a lower than system average increase for the General Service Primary rate class.

6. The updated CCOSS identifies a larger percentage of the General Service Primary customer rate class revenue requirement as customer-related and less as demand-related.

7. Company evidence shows that the General Service Transmission ("GST") class would have a rate of return of 28% without the credit for power factor improvement. Since an increase in power factor reduces system costs, that fact should be included in the revenue allocation to Rate GST and it is recommended that Rate GST customers receive no more than one-half of the system average percentage increase granted by the Commission in this proceeding.

II. COST OF SERVICE OVERVIEW

Q WHAT INFORMATION IS CONTAINED IN A CCOSS?

A A CCOSS compares the cost that each customer class imposes on the system to the revenues each class contributes. This relationship is generally presented by comparing the rate of return that a class is providing with the utility's overall jurisdictional rate of return.

For example, when a customer class produces the same rate of return as the total jurisdictional utility rate of return, the customer class is paying revenue to the utility just sufficient to cover the costs that the utility incurs to serve that class. If a class produces a below-average rate of return, it may be concluded that the revenue provided by the class is insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce below system average rates of return.

Q **WHY IS A CCOSS OF IMPORTANCE?**

A A CCOSS shows the costs that a utility incurs to serve each customer class. It is a widely held principle that costs should be allocated among customer classes on the basis of cost-causation. That principle is perhaps the most universally accepted principle of allocating cost that cannot be directly assigned to a particular customer class. The costs should be allocated to those classes on the basis of cost causation. The results of such studies are used in assigning cost responsibilities to various customer classes in regulatory proceedings.

Q **DO YOU SUPPORT THAT PREMISE?**

A. Yes. Rates that are based on consistently applied cost causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs, but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

Q HOW IS THE COST OF SERVING EACH CUSTOMER CLASS DETERMINED?

A The appropriate mechanism to determine the cost of serving each customer class is a fully allocated embedded CCOSS. It follows, however, that the objective of cost-based rates cannot be attained unless the CCOSS is developed using cost-causation principles.

Q WHAT ARE THE MAJOR STEPS IN A COST OF SERVICE STUDY?

A The first step in a CCOSS is known as functionalization. This simply refers to the process by which the Company's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as classification. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related, and customer-related costs in order to facilitate the allocation of costs applying the cost-causation principles.

Demand or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines, and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. Thus, the fuel expense is almost directly proportional to the amount of kilowatthours supplied by the utility system to meet its customers' energy requirements. It should be noted that none of the distribution costs are energy-related.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services, and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation, and revenue accounting are considered customer-related cost.

The final step in the CCOSS is the <u>allocation</u> of each category of the functionalized and classified costs to the various customer classes using the cost-causation principles. Demand-related costs are allocated on the basis that gives recognition to each class's responsibility for the Company's need to build plant to serve demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Since no costs in this case are energy-related, the use of energy allocators is not appropriate. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

III. COST OF SERVICE AND REVENUE ALLOCATION/RATE DESIGN PRINCIPLES

Q WHY IS IT IMPORTANT TO ADHERE TO COST OF SERVICE PRINCIPLES IN THE REVENUE ALLOCATION/RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve the customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility (and other competitive power suppliers) about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on actual costs do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the impact on the utility's earnings due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power cost.

IV. DELMARVA'S COST OF SERVICE STUDY

Q HAVE YOU REVIEWED THE CCOSS FILED BY DELMARVA IN THIS PROCEEDING?

A Yes. I have reviewed the results of Delmarva's test year electric cost of service study. The test year is based on a 12-month period ending December 31, 2012. The results of the study are identified on Schedule EPT-1 and summarized in Table 1 below.

TABLE 1

Delmarva CCOSS Results at Current ROR Level

Rate Class	Rate of Return (1)	Relative Rate of Return (2)
Residential	4.34%	0.97
Residential Space Heating	2.68%	0.60
Gen. Service Secondary Small	9.38%	2.10
Gen. Service Secondary Large	4.54%	1.02
Gen. Service Primary	1.77%	0.40
Gen. Service Transmission	-4.23%[1]	-0.95
Street Lighting	4.98%	1.12
Total Delaware Retail	4.47%	1.00

[1]The Rate GST per book revenues include a power factor credit. Excluding this credit would increase the Rate GST class ROR to approximately 28%.

Q DO YOU HAVE ANY CONCERNS WITH DELMARVA'S CCOSS?

A Yes, I take exception with the classification and allocation of certain distribution costs as entirely demand-related. Specifically, I object to the classification and allocation associated with Distribution Plant Accounts: 364 (Poles, Towers and Fixtures); 365 (Overhead Conductors and Devices); 366 (Underground Conduit); and 367 (Underground Conductors and Devices). The costs associated with these accounts should be classified and allocated based on both demands and customer counts.

Q **WHY SHOULD THE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 367 BE CLASSIFIED AND ALLOCATED ON BOTH A DEMAND AND CUSTOMER BASIS AS OPPOSED TO JUST A DEMAND BASIS AS PERFORMED IN DELMARVA'S CCOSS?**

A Classifying and allocating the costs associated with Distribution Plant Accounts 364 through 367 entirely on a demand basis is inconsistent with cost-causation and generally accepted costing methodology. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer in various geographical locations with service at different voltage levels. Certain distribution investments must be made just to connect a customer to the system. Also, many equipment manufacturers have only minimum sized equipment available. Safety concerns and construction practices often require minimum sized equipment which is not determined by demand. These investments are properly considered to be customer-related.

Q **IS THIS A NEW COST OF SERVICE CONCEPT?**

A No. The concept is known as the minimum distribution system ("MDS"), and has been accepted for decades as a valid consideration by numerous state public utility commissions. It has also been presented in the National Association of Regulatory

Utility Commissioners Electrical Utility Cost Allocation Manual ("NARUC Manual") and the Gas Distribution Rate Design Manual published by NARUC.

The central idea behind the MDS concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution systems and connects an additional customer to them. By definition, the MDS system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers. It does not include costs specifically incurred to meet the peak demand of the customers.

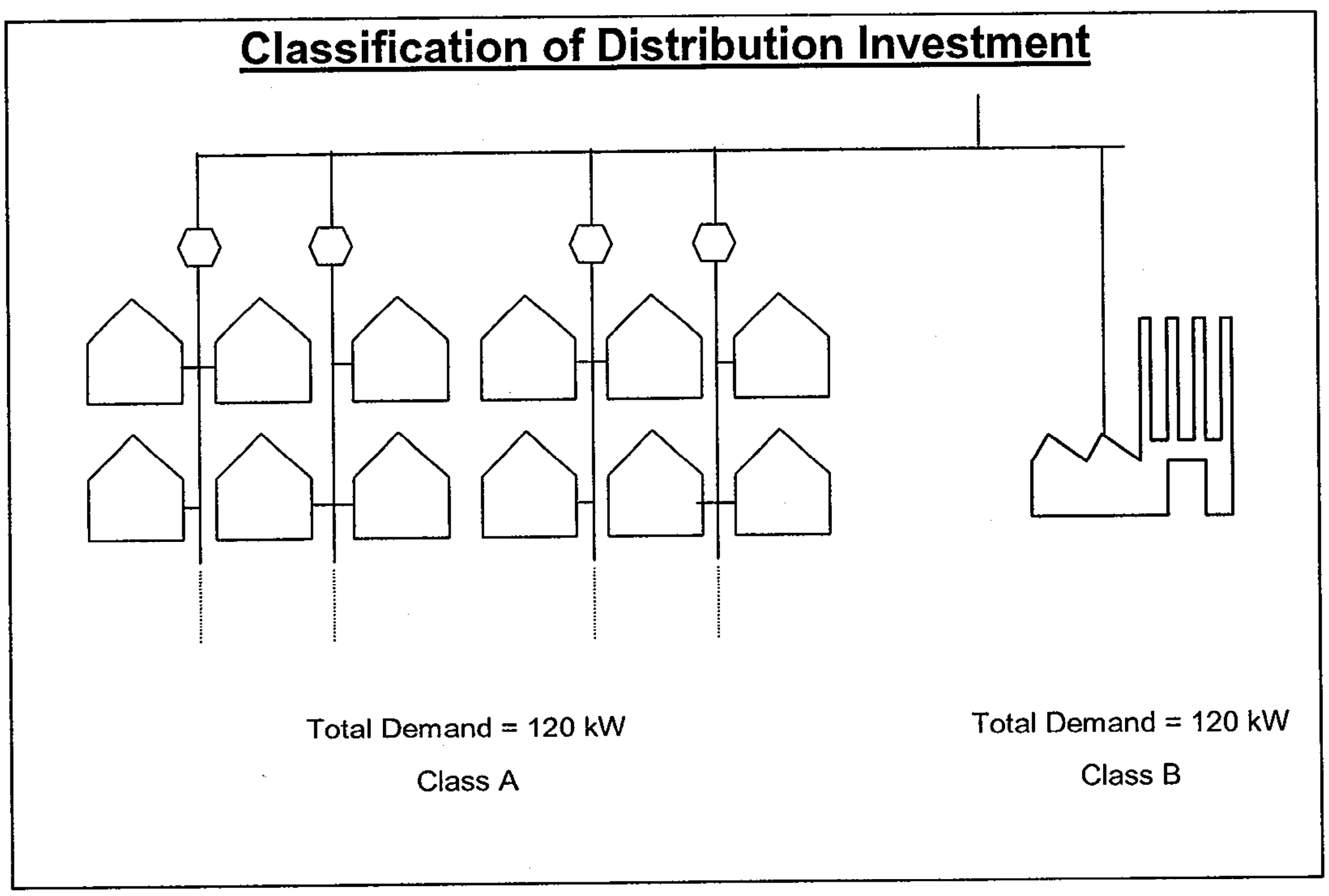
Q PLEASE ELABORATE FURTHER ON THE MDS CONCEPT AND THE DISTINCTION BETWEEN CUSTOMER-RELATED COSTS AND DEMAND-RELATED COSTS IN THE CONTEXT OF A CLASS COST OF SERVICE STUDY.

A A certain portion of the cost of the distribution system–poles, wires and transformers–is required just to attach customers to the system in different geographical locations, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered as customer-related cost since it depends primarily on the number of customers, rather than on demand or energy usage.

Figure 1, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers in different geographical locations requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair. Thus, a large part of the distribution system is classified as customer-related in order to recognize this area coverage requirement.

Figure 1



Q IN ADDITION TO THE AREA COVERAGE FACTOR YOU NOTED ABOVE, ARE THERE OTHER REASONS FOR CLASSIFYING PART OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A Yes, there are. Safety and reliability are the best example of these. A properly conducted class cost of service study must consider all cost-causing factors.

Q PLEASE EXPLAIN.

A When distribution engineers design the enhancement, upgrade, or extension of an electric system, they must be constantly aware of the operating parameters of the system. It is in the construction of the distribution system, however, that the *true cause* of many distribution costs is clearly seen. Surprisingly, that cause is frequently *not* demand.

An illustration helps make this point clear. Consider a customer who intends to build a home on a new lot, one that does not already have electrical service. This customer is cost and energy conscious and, thus, chooses to employ as many energy efficiency and conservation techniques and appliances as he can. After considerable research and consultation with experts, the customer calls the utility and advises that he will require service capable of providing a maximum peak demand of 2,000 watts (2 kW).

During the installation of the primary and secondary distribution extension to the customer's home, he notices that the linemen are using conductors, poles, cross-arms, and components identical to those serving the much larger, and less efficient, houses down the street. After more investigation, the customer learns that the distribution extension to his home is capable of carrying far greater demand than his home was designed to use. When he informs the utility of this 'error,' the utility explains that because of reliability and safety concerns it cannot install wires smaller than a certain size or hang them below a certain height. In short, there are specified minimum standards that the utility must meet that are wholly unrelated to the new home's reduced demand.

This illustration demonstrates that, although utilities design and install distribution equipment to satisfy their customers' need for electricity, there are factors other than electrical demand that force them to incur costs. Safety and reliability are as critical to every phase of design and construction as demand. Further, many equipment manufacturers have only minimum sized equipment available for installation. As one reviews the cost of the distribution system nearest the customer (i.e., that portion from the primary radial lines through the line transformers and secondary system), the cost incurred to comply with safety and reliability standards, as well as minimum sized equipment available, begins to outweigh the cost of meeting electrical demand.

Q CAN YOU CITE ANY AUTHORITATIVE PUBLICATIONS THAT SUPPORT ALLOCATING PART OR ALL OF PLANT ACCOUNTS 364 THROUGH 367 ON THE BASIS OF A CUSTOMER COMPONENT?

A Yes. In 1992, NARUC published the NARUC Manual which states:

> "Distribution Plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities." (NARUC Manual, page 90)

Table 6-1 from the NARUC Manual is included as Figure 2. It shows that Distribution Plant Accounts 364 through 367, which include conductors and support structures, have both a demand component and a customer component.

Figure 2

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant[2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems[1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

Q **HAVE UTILITY COMMISSIONS ADOPTED ALLOCATION METHODS FOR CLASSIFYING AND ALLOCATING A PORTION OF DISTRIBUTION PLANT AS CUSTOMER-RELATED?**

A Yes. For example, the Connecticut, Colorado, Hawaii, Indiana, Kansas, Maine, Missouri, New York, North Carolina, Oregon, Pennsylvania, Texas and Wisconsin

Commissions have classified a portion of the Distribution Plant Accounts 364 though 367 on a customer- and demand-related basis for cost of service purposes.

Q HAS DELMARVA EVER SUPPORTED THE USE OF A CUSTOMER COMPONENT IN THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 367?

A Yes. In Docket No. 11-528, as provided in response to DEUG-1-17, Delmarva supported a customer component in Docket No. 92-85. Further, in Delmarva's last electric distribution rate proceeding in Maryland, Case No. 9249, as part of the settlement, Delmarva agreed to provide both a zero intercept and minimum system cost of service study, identifying which portion of their distribution system is customer related. A copy of the Maryland Commission approved Settlement Agreement in Case No. 9249 is attached as Exhibit NP-1.

Q DID DELMARVA PROVIDE THE RESULTS OF A ZERO INTERCEPT AND MINIMUM SYSTEM COST OF SERVICE STUDY IN CASE NO 9249?

A Yes. On December 9, 2011, in Case No. 9249, Delmarva provided the results of its Minimum Distribution System and Zero-Intercept studies. A copy of those studies are attached as Exhibit NP-2. Exhibit NP-3 is a summary of the customer and demand classification results from Delmarva's distribution studies.

Q BASED ON YOUR EXPERIENCE, ARE THESE DISTRIBUTION PLANT CUSTOMER COMPONENT LEVELS CONSISTENT WITH THOSE LEVELS USED BY OTHER UTILITIES WHO CLASSIFY A PORTION OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 367 AS CUSTOMER RELATED?

A Yes. In my experience, the customer component used by other utilities who classify a portion of Distribution Plant as customer related is in the range of 30% to 50%.

Q ARE YOU AWARE OF ANY CRITICISMS OF MINIMUM DISTRIBUTION STUDIES RELATED TO THE MINIMUM SYSTEM AND ZERO-INTERCEPT METHODS?

A Yes. The studies provided by the Company cite criticisms of both methods which can also be found in the NARUC Manual. There are two primary criticisms associated with the minimum system method. The first criticism is that the selection of the minimum system is largely subjective and varies with the methods used to size minimum equipment. The second criticism is that even a minimum size distribution system has the capability to carry some load.

There are also two major criticisms associated with the zero-intercept method for determining a minimum distribution system. The first criticism is that the method ignores that there is a weak correlation relating the area and mileage of a distribution system to the number of customers served. The second criticism is that the zero-intercept method requires much more extensive data and an understanding of statistics in order to generate reliable results.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT COSTS ASSOCIATED WITH ACCOUNTS 364 THROUGH 367?

A The Commission should use the results of a cost of service study that classifies and allocates a portion of distribution plant costs associated with Accounts 364 through 367 on a customer basis. This approach is consistent with general ratemaking policy objectives, such as customer equity, conservation and revenue stability. This adjusted cost of service study should be used as a guideline in revenue allocation and rate design in this proceeding.

Q DID YOU PREPARE A CCOSS CLASSIFYING AND ALLOCATING A PORTION OF DISTRIBUTION PLANT COSTS ASSOCIATED WITH ACCOUNTS 364 THROUGH 367 ON A CUSTOMER BASIS?

A Yes. In response to PSC-COS-18 Delmarva provided an electronic copy of its distribution CCOSS. I revised Delmarva's CCOSS by classifying the costs associated with Distribution Plant Accounts 364 through 367 utilizing the average customer component from Exhibit NP-3. I utilized the demand allocators proposed by Delmarva and the customer counts from its CCOSS.

Q EARLIER YOU MENTIONED SOME CRITICISMS ASSOCIATED WITH THE METHODS USED TO DETERMINE THE MINIMUM DISTRIBUTION SYSTEM, HOW DID YOU MODIFY YOUR STUDY TO ADDRESS THESE CRITICISMS?

A The study provided by the Company offered recommendations to adjust the demand and customer allocators associated with the distribution system. I used these recommendations as a starting point for the adjustments I made. The recommendations, both for the minimum size study and for the zero-intercept study, did not suggest making any adjustments to the allocators associated with the primary system and no adjustments were recommended for the demand allocator associated with the secondary system with respect to the zero-intercept method. However, adjustments were recommended for the customer allocation factor associated with the secondary system for both the zero-intercept and minimum size studies, as well as, the demand allocator for the secondary system for the minimum size study.

After I determined the adjusted allocation factors, I then averaged the allocation factors together to combine the results of the minimum size and zero-intercept studies. I performed this blending technique to adjust the studies to account for the subjective estimates used in the individual studies (specifically the subjective assessment of the minimum size system used in the minimum size study, and the estimated data used in the zero-intercept study).

Q WHAT IS THE COST OF SERVICE IMPACT ASSOCIATED WITH CLASSIFYING AND ALLOCATING A PORTION OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 367 ON A CUSTOMER BASIS?

A Exhibit NP-4 shows the results of the updated CCOSS, which classifies the costs associated with Distribution Plant Accounts 364 through 367 on the basis of customer and demand. The results of the revised cost of service study show an increase in cost allocation to the Residential customer class. Costs are reduced for the General Service Secondary class and General Service Primary class, while costs for the General Service Transmission class remained virtually unchanged.

Q **HOW DO THE RESULTS OF YOUR REVISED CCOSS COMPARE TO THE CCOSS FILED BY DELMARVA?**

A The total cost of service by customer class under Delmarva's CCOSS and my revised CCOSS are shown on Exhibit NP-5. The results of the revised CCOSS, which takes into account actual cost utilization principles, should be used to allocate any distribution revenue increase in this proceeding, as well as the design of distribution rates.

While data requirements and certain aspects of developing a customer component may be criticized, using no customer component is clearly wrong and produces erroneous results. A conservative implementation of a customer component is a fair and reasonable approach that should be used in the CCOSS and is also in accord with the NARUC Manual.

V. REVENUE ALLOCATION

Q **HAS DELMARVA ALLOCATED ITS REQUESTED LEVEL OF DISTRIBUTION INCREASE IN THIS CASE RECOGNIZING THE RESULTS OF THEIR CCOSS?**

A Yes. As shown on Schedule MCS-1, page 1 of 2, from the Direct Testimony of Company witness Marlene Santacecilia, Delmarva's proposed revenue distribution was developed with the intent to move rate classes closer to cost of service. However, in order to ensure that no rate class receives an inordinate level of increase, Delmarva limited the level of increase to any one service classification to 1.5 times the overall distribution percentage increase. As shown on Schedule MCS-1, the Residential Space Heating, General Service Primary and the General Service Transmission rate classes all receive revenue increases above the system average level of increase, while the Residential (non-space heating), Small and Large

General Service Secondary and Street Lighting customer classes receive revenue increases below the system average.

Q HAVE YOU DEVELOPED A RECOMMENDED SPREAD OF THE INCREASE, ASSUMING FULL REVENUE RELIEF FOR THE COMPANY, AND USING YOUR CORRECTED CCOSS?

A Yes. The results are shown on Exhibit NP-6. As shown on Exhibit NP-6, the Residential (Non-Space Heating) rate class, the Small and Large General Service Secondary rate classes along with the General Service Primary and Street Lighting rate classes receive rate increase levels that are below the system average level of increase. The remaining rate classes, Residential Space Heating and General Service Transmission receive rate increases that are above the system average level of increase. However, the Rate GST increase should be limited to no more than one half of the system average percentage increase to reflect the power factor benefit to the system associated with this class.

Q PLEASE EXPLAIN YOUR RECOMMENDATION TO LIMIT THE RATE GST INCREASE TO ONE-HALF OF THE SYSTEM AVERAGE PERCENTAGE INCREASE.

A Rate GST is a unique class of seven customers served at transmission voltage. The GST rate provides for a credit or penalty for a power factor above or below 90%. Customers that increase their power factor above 90% receive a credit of $0.03 per kW of measured demand for every whole percent above 90%. An increase in power factor is desirable and reflects a benefit to the system and generally lowers overall cost to the system. The rate of return of the Rate GST class is a negative 4.23% with the credit to revenues and 28% without. These customers should not be penalized with a large rate increase for taking action at their own expense in response to a price signal to provide benefit to the system. A fair and reasonable approach is to limit the increase to Rate GST to one-half of the system average percentage increase.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q **PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A The Commission should adopt my recommended adjustments to Delmarva's proposed class revenue allocation. My specific recommendations and conclusions are as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level and design of rates charged to customers.

2. Delmarva's CCOSS comports with generally accepted cost of service study methods. However, the classification and allocation of certain distribution plant accounts in Delmarva's CCOSS should be modified to classify a portion of those costs as customer-related.

3. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments must be made to connect a customer to the system. Therefore, these investments are considered customer-related.

4. Updating Delmarva's CCOSS to reflect a reasonable customer component in the classification and allocation of certain distribution plant costs shows that at current rates, the rates associated with the General Service Secondary and General Service Primary rate classes are above cost of service.

5. Delmarva's CCOSS appears to not adequately credit the General Service Transmission customer class for system cost reductions related to power factor improvement while reducing revenues for the power factor component.

6. With the exception of the General Service Transmission class results, the results of the revised CCOSS, which takes into account actual cost utilization principles, should be used to allocate any distribution revenue increase in this proceeding as well as the design of distribution rates. The revised CCOSS supports a lower than system average increase for the General Service Primary rate class. As previously stated, the GST class should be limited to one-half of the system average percentage increase.

7. The updated CCOSS identifies a larger percentage of the General Service Primary customer rate class revenue requirement as customer-related and less as demand-related.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Nicholas Phillips, Jr.

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A I graduated from Lawrence Institute of Technology in 1968 with a Bachelor of Science Degree in Electrical Engineering. I received a Master's of Business Administration Degree from Wayne State University in 1972. Since that time I have taken many Masters and Ph.D. level courses in the field of Economics at Wayne State University and the University of Missouri.

I was employed by The Detroit Edison Company in June of 1968 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included the overhead and underground design, construction, operation and specifications for transmission and distribution equipment; budgeting and cost control for operations and capital expenditures; equipment performance under field and laboratory conditions; and emergency service restoration. I also worked in various districts, planning system expansion and construction based on increased and changing loads.

Since 1973, I have been engaged in the preparation of studies involving revenue requirements based on the cost to serve electric, steam, water and other portions of utility operations.

Other responsibilities have included power plant studies; profitability of various segments of utility operations; administration and recovery of fuel and purchased power costs; sale of utility plant; rate investigations; depreciation accrual rates; economic investigations; the determination of rate base, operating income, rate of return; contract analysis; rate design and revenue requirements in general.

I have held various positions including Supervisor of Cost of Service, Supervisor of Economic studies and Depreciation, Assistant Director of Load Research, and was designated as Manager of various rate cases before the Michigan Public Service Commission and the Federal Energy Regulatory Commission. I was acting as Director of Revenue Requirements when I left Detroit Edison to accept a position at Drazen-Brubaker & Associates, Inc., in May of 1979.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff.

Our firm has prepared many studies involving original cost and annual depreciation accrual rates relating to electric, steam, gas and water properties, as well as cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

In general, we are engaged in valuation and depreciation studies, rate work, feasibility, economic and cost of service studies and the design of rates for utility services. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND AFFILIATIONS HAVE YOU HAD?

A I have completed various courses and attended many seminars concerned with rate design, load research, capital recovery, depreciation, and financial evaluation. I have served as an instructor of mathematics of finance at the Detroit College of Business located in Dearborn, Michigan. I have also lectured on rate and revenue requirement topics.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have appeared before the New Jersey Board of Public Utilities, the Public Service Commissions of Arkansas, Delaware, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Montana, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Virginia, West Virginia, and Wisconsin, the Lansing Board of Water and Light, the District of Columbia, and the Council of the City of New Orleans in numerous proceedings concerning cost of service, rate base, unit costs, pro forma operating income, appropriate class rates of return, adjustments to the income statement, revenue requirements, rate design, integrated resource planning, power plant operations, fuel cost recovery, regulatory issues, rate-making issues, environmental compliance, avoided costs, cogeneration, cost recovery, economic dispatch, rate of return, demand-side management, regulatory accounting and various other items.

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ORDER NO. 84170

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	*	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND
	*	CASE NO. 9249, PHASE I
IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	*	CASE NO. 9249, PHASE II

Issue Date: July 8, 2011

To: Service List for Case No. 9249

I. INTRODUCTION AND EXECUTIVE SUMMARY

In this Order, we approve a *Joint Motion for Approval of Agreement of Unanimous Stipulation and Settlement* (collectively, "Settlement"). We approve the Settlement because we find that, under the circumstances and on the record before us, the unanimous agreement of the parties[1] will result in just and reasonable rates for Delmarva Power & Light Company ("Delmarva" or "Company") and its customers and is consistent with the public interest. The rate increase contained in the Settlement, a total of $12.2 million in distribution revenue, is significantly less than the Company's original $17.803 million request and well below the original recommendation of the Commission's Technical Staff. In addition to the Company and our Staff, the Settlement

[1] In addition to the Company, three other parties participated in this case: the Public Service Commission's Technical Staff ("Staff"); the Office of People's Counsel ("OPC"); and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Walmart") (collectively, with the Company, "parties").

is supported by the Office of People's Counsel, which represents the State's residential customers, and by Wal-Mart, the only other intervenor in the case. Although we do not grant any increase lightly, we find that the rate changes for the various rate classes, including an increase of $1.78 per month for the average residential customer using 1,000 kilowatts per month ("kWhs"), which represents a 1.4% increase in the total monthly electric bill of the average residential customer, are supported by this record. We agree that the Company should prepare certain cost of service studies recommended by Staff, and that it should do so prior to its next rate case so that those studies are available when we next consider Delmarva's rates.

Finally, we are willing to allow the parties to discuss regulatory lag issues in a work group, as the Settlement provides. But approval of this Settlement should not be read as a recognition (let alone a finding) on the part of this Commission that regulatory lag is a problem for Delmarva (or any other company) that needs to be solved. We approve this element of the Settlement based on the parties' testimony that their agreement does not require or bind us to adopt or implement any recommendations the work group might file, nor to undertake further proceedings to consider them. In our view, the Settlement removes regulatory lag from our consideration at this time, but we will consider the need for and mechanics of any regulatory lag measures at an appropriate time, on a full and complete record.

II. BACKGROUND

On December 21, 2010, Delmarva Power & Light Company filed an Application with the Public Service Commission ("Commission") pursuant to §§ 4-203 and 4-204 of the Public Utilities Article, *Annotated Code of Maryland* ("PUA"), for authority to increase its retail electric rates in Maryland. Delmarva's last electric rate case occurred in 2009.[2] The Company requested a $17,803,000 increase in electric rates based upon a test year ending December 31, 2010, using nine months of actual data and three months of estimated data.[3] According to the Application, approval of this request would have resulted in a 2.8% overall increase in rates for a typical residential customer who uses 1,000 kWhs of electricity per month.[4] Delmarva submitted supplemental direct testimony on February 28, 2011, based upon actual 2010 test year data, which it claimed supported an $18,262,000 increase, although the Company did not revise its revenue increase request.[5] In its May 10, 2011 rebuttal filing, the Company revised its final revenue requirement request to $16,469,000.[6]

Three other parties participated in this case, the Public Service Commission's Technical Staff ("Staff"), the Office of People's Counsel ("OPC") and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Walmart"). These parties filed direct testimony on April 11, 2011. Delmarva and Staff filed rebuttal testimony on May 10, 2011. Surrebuttal testimony was filed by the Staff and OPC on May 20, 2011.

Staff originally recommended a revenue increase of no more than $14,796,917,[7] but revised its recommendation to $13,386,046 after reviewing the direct testimony of other parties.[8] OPC initially recommended limiting the rate increase to $9,733,000,[9] but

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[2] *Re Delmarva Power and Light Company,* Case No. 9192, Order Nos. 83040 and 83085, 100 MD PSC 431, 435 (2009).
[3] Application at 2.
[4] Application at 2.
[5] Supplemental Direct Testimony of Delmarva Witness W. Michael VonSteuben at 2.
[6] VonSteuben Rebuttal at 16.
[7] Direct Testimony of Staff Witness Patricia M. Stinnette at 2.
[8] Stinnette Rebuttal at 1.
[9] Direct Testimony of OPC Witness David J. Effron at 2.

subsequently adjusted its recommendation to $9,979,000.[10] Walmart filed testimony that recommended rejecting the Company's attrition proposals.[11]

III. SETTLEMENT AGREEMENT

The parties reviewed the testimony filed in this matter and unanimously determined that it was appropriate to propose a settlement to the Commission in this case. On May 25, 2011, Delmarva, Staff, OPC, and Walmart filed a *Joint Motion for Approval of Agreement of Unanimous Stipulation and Settlement.* The Company, Staff and OPC filed testimony in support of the Settlement on June 1, 2011.[12] The Commission held an evidentiary hearing about the proposed Settlement on June 6, 2011. Evening hearings to receive public comments were held on June 13, 14 and 15, 2011 in Chestertown, Salisbury and Wye Mills, Maryland, respectively.[13]

The Settlement provides that Delmarva shall file new base rate schedules that increase electric distribution rates by $12.2 million.[14] The Settlement stipulates the agreed-upon allocation of base rates among all customer classes, subject to verification by Staff.[15] Additionally, the Settlement establishes a Regulatory Lag Work Group that will address Delmarva's claims that regulatory lag prevents it from having an opportunity to earn its authorized return and that its approved rates should include certain regulatory

[10] Effron Surrebuttal at 1.
[11] Direct Testimony of Walmart Witness Steve W. Chriss.
[12] Counsel for Walmart stated its support for the Settlement at the June 6, 2011, hearing.
[13] No citizens appeared and offered comments at any of the hearings, which were noticed properly and in a timely manner in publications throughout Delmarva's service territory. We understand that one of the evening hearings was held on the same night as a hearing on proposed highway toll increases, but there was no such conflict with the other two evening hearings.
[14] Settlement provision No. 2.
[15] Settlement provision No. 4 and Exhibit 2.

lag mitigation measures.[16] The Settlement provides that the work group will attempt to reach consensus "on the need for a proposed mechanism or the design of such a mechanism to address regulatory lag"; if it does, the group will submit that proposal to the Commission or, if not, the parties may submit separate proposals.[17] All parties "retain the right to oppose any proposal made and any representations made with regard to the need to have a mechanism to address regulatory lag," and OPC specifically agreed to participate in the work group in good faith, but "without prejudice to its right to take the position that the existence of regulatory lag has not been established in this or any other proceeding or that no mechanism is necessary to address the issue of regulatory lag in this or any other proceeding."[18] The parties also stipulated to details regarding regulatory cost rates, the amortization of February 2010 winter storm costs and future cost of service studies.[19]

The parties stipulated that all issues that they identified are settled and that they "agree that the resolution of the issues herein, taken as a whole, results in just and reasonable rates and are in the public interest."[20] The Settlement also requests that new rates become effective June 15, 2011, "or as soon as reasonably practicable thereafter."[21] The parties agreed to the admission of all pre-filed testimony in support of the Settlement.[22] Finally, the Settlement contains standard general provisions,[23] specifically

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[16] Settlement provision No. 5. The work group shall last for no more than 100 days. *Id.*
[17] Settlement provision No. 5.
[18] *Id.*
[19] Settlement provision No. 6.
[20] Settlement provision No. 1.
[21] Settlement provision No. 3.
[22] Settlement provision No. 7.
[23] Settlement provisions Nos. 8 through 13.

that the Settlement is void if it is not approved without modification by the Commission.[24]

In support of the Settlement, Delmarva submitted the testimony of Anthony J. Kamerick, Senior Vice President and Chief Financial Officer of Pepco Holdings, Inc. ("PHI").[25] He states that the Settlement is in the public interest because: (1) it balances the needs and interests of various stakeholders with adverse interests in this case; (2) it will allow the Company to recover its costs and maintain its financial health; and (3) it will permit the parties and the Commission to conserve resources and avoid the costs of litigation.[26] Specifically, he notes that the rate increase will be applied to each customer class in accordance with the Company's class cost of service study ("COSS"), which is designed to move each individual rate class closer to the overall system rate of return.[27] Mr. Kamerick argues that the $12.2 million Settlement amount is "clearly supported" by the positions of Staff and Delmarva, which recommended revenue increases of $13.3 million and $16.5 million, respectively. He concludes that taking into account litigation risk, costs and timing, the Settlement amount represents a fair compromise.[28] Mr. Kamerick states that the average residential customer using 1,000 kWhs per month will experience an increase of $1.78 per month, which represents a 1.4% increase in the total bill. Other customer classes will experience increases ranging from 1.3% to 5.4%. Moreover, Mr. Kamerick notes that the Consumer Price Index has risen 3.2% in the last year, which substantiates the reasonableness of the Settlement.[29] Finally, he noted the

[24] Settlement provision No. 9.
[25] PHI is the parent company of Delmarva.
[26] Settlement Testimony of Anthony J. Kamerick at 1-2.
[27] Kamerick at 3.
[28] Kamerick at 4.
[29] Kamerick at 4-5.

importance to the Company of the Regulatory Lag Work Group, arguing that the Company's professed inability to earn its authorized return due to regulatory lag is an important issue. He emphasized that if a regulatory lag mechanism can be agreed upon by the parties that they would then request Commission approval of the mechanism. If the parties cannot agree, then they would be free to submit proposals to the Commission to address the issue of regulatory lag.[30] But at the hearing, Mr. Kamerick acknowledged that the Settlement did not require the Commission to adopt any proposal, consensus or otherwise, nor did the parties expect that the Commission would adopt any regulatory lag mechanisms in this case or necessarily hold further proceedings on regulatory lag.[31]

Staff filed the testimony of Patricia M. Stinnette, a Commission Public Utility Auditor, Program Specialist, and Phillip E. VanderHeyden, Director of the Electricity Division. According to Ms. Stinnette, Delmarva is not currently earning a reasonable return, which is evidenced by the parties' unanimous agreement that the Company has a revenue deficiency. She states that the $12.2 million Settlement amount lies between the parties' positions and concludes that it is "within the range of reasonableness."[32]

According to Mr. VanderHeyden, the Settlement adopts the Company's revenue allocation proposal, which the Commission accepted in Delmarva's two preceding rate cases, Case Nos. 9093 and 9192.[33] Additionally, he notes that the revenue increase for each class is applied on an equal percentage basis to both fixed and variable charges, which Staff supported in its testimony.[34] Mr. VanderHeyden concludes that the

[30] Kamerick at 5-6.
[31] Transcript of June 6, 2011 Hearing ("Tr.") at 22-27.
[32] Settlement Testimony of Patricia M. Stinnette at 3.
[33] Settlement Testimony of Phillip E. VanderHeyden at 2-3.
[34] VanderHeyden at 2.

Settlement represents a reasonable allocation of costs and that rates are reasonably designed. [35] He recommends that the Company file compliance tariffs to allow for minor adjustments to each rate and file updated average monthly class revenue for the Bill Stabilization Adjustment calculation.[36] Finally, he notes that the Settlement incorporates Staff's proposal that the Company file a minimum system and a zero intercept COSS in its next rate case, which should provide insight into the proper level of fixed customer charges versus variable distribution rates.[37]

OPC witness Effron concludes that overall the Settlement terms and conditions, including the $12.2 million revenue increase, are reasonable.[38] He notes that both the Company and Staff reduced their recommended revenue requirements in this case after accepting some of his proposed adjustments.[39] After these adjustments, he notes that the Settlement amount was significantly closer to OPC's recommended amount ($9.979 million) than to the Company's request ($16.469 million) and is also below Staff's ($13.386 million) recommendation. Mr. Effron emphasizes that state commissions, including this one, usually find that the appropriate revenue increase is between the low and high recommendations of the parties.[40] Consequently, he concludes that under the circumstances of this case that the Settlement "results in just and reasonable rates and [is] in the public interest."[41]

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[35] VanderHeyden at 1.
[36] VanderHeyden at 3.
[37] VanderHeyden at 3-4.
[38] Supplemental (Settlement) Testimony of David J. Effron at 4.
[39] Effron at 3.
[40] Effron at 4.
[41] Effron at 5.

IV. COMMISSION DECISION

The Commission has in the past considered and approved settlements proposed by adverse parties representing divergent interests in a proceeding.[42] We acknowledge that delicate compromises are often required in order for parties to achieve an uncontested settlement. Historically, a settlement that is submitted by parties who normally have adverse interests is an indication that the overall agreement reached is a reasonable one. However, the mere fact of a settlement does not end our inquiry – we must review any settlement carefully to ensure that the outcome, and the resulting rates, are indeed just and reasonable. In addition to reviewing the record developed by the parties during this case, we have thoroughly reviewed this Settlement and the testimony filed in support of it, and based upon the record, we approve the Settlement for the reasons we explain below.

The parties' final revenue requirement positions ranged from a high of $16.5 million, as advocated by the Company, to a low of $10 million, advocated by OPC. Staff's final recommendation was $13.4 million. Thus, the Settlement, with an agreed revenue requirement of $12.2 million, is less than that recommended by two of the three parties that presented revenue requirement testimony. Moreover, OPC witness Effron testified that after the Company accepted several of his recommended revenue requirement adjustments, the revenue increase agreed to in the Settlement is "significantly closer" to OPC's recommendation than it is to the Company's requested increase.[43] Finally, the parties agreed to a rate design that will move all classes closer to

[42] *Re Delmarva Power and Light Company,* Case No. 8795, Order No. 75680, 90 MD PSC 115 (1999).
[43] Supplemental Testimony of David J. Effron at 4.

the system-wide unitized rate of return, which is consistent with the policy we have stated in recent Delmarva rate case opinions.[44] Therefore, under the circumstances of this case and based on this record developed throughout this proceeding, we find that the revenue requirement and rate design incorporated in the Settlement will result in just and reasonable rates.

The Company made several recommendations in this case to address its concern with a perceived issue of regulatory lag. Delmarva focused particularly on two proposals, a reliability investment mechanism ("RIM") and an annual rate of return review process ("ARRP"). The other three parties opposed these proposals. In order to settle this case, the parties all agreed to request a Phase II proceeding, which will involve the establishment of a Regulatory Lag Work Group to examine the need for, and design of, any regulatory lag mechanism.[45]

During the June 6, 2011, hearing on the Settlement, the Commission questioned the parties regarding their expectations. Delmarva witness Kamerick stated that if a regulatory lag mechanism is agreed upon, the parties would present it to the Commission for consideration. He acknowledged, though, that it would be entirely up to the Commission to decide whether to implement it and if so when.[46] Further, he emphasized that the Settlement does not bind the Commission in any way regarding the Phase II proceeding or to take any action on any proposals the parties might file,[47] and that the operative terms of the Settlement would bind the parties even if we were to find that a

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[44] *See* provision No. 4 of the Settlement and Settlement Testimony of Phillip E. VanderHeyden at 2-3. In response to Commission inquiry at the June 6, 2011 hearing, the Company provided updated information regarding the unitized rate of return for each rate class on June 13, 2011. That filing, identified as ML# 131940, is hereby admitted into the record.
[45] Settlement provision No. 5.
[46] Tr. at 23.
[47] Tr. at 27.

regulatory lag mechanism should not be approved outside of the context of a rate case.[48] However, Mr. Kamerick stated that, without some sort of regulatory lag mechanism, the Company would file future rate cases on a more frequent basis.[49] Both the Staff and OPC witnesses concurred with Mr. Kamerick's assessment that the Settlement merely requires the parties to meet and discuss regulatory lag matters, and that it in no way binds us to any outcome, whether a consensus or not or to take any further action to address regulatory lag.[50]

The concept of regulatory lag is not a new one in ratemaking, but we have no quarrel with the idea that Delmarva and the other parties might meet after we issue this Order to discuss regulatory lag and Delmarva's request for relief in some fashion. They would be free to do so with or without the imprimatur of this Settlement, in fact. We want to make clear, however, that adoption of the sort of regulatory lag mechanisms Delmarva proposes here would represent a significant shift in ratemaking policy for this Commission. In recent years, for example, we have considered and rejected Delmarva's request for surcharge recovery outside of rates for pension and other employment costs,[51] surcharge recovery for BGE's advanced metering buildout,[52] and opposed legislation that would mandate surcharge recovery for infrastructure expenditures. We have considered these decisions and positions carefully and explained ourselves at length, grounding them all in the fundamental ratemaking principle that surcharge recovery of core expenses

[48] Tr. at 24-26.
[49] Tr. at 28-33.
[50] Tr. at 38-39 and 41-42.
[51] *Re Delmarva Power and Light Company,* Case No. 9192, Order No. 83085, 100 MD. PSC 435, 445-446 (2009).
[52] *In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to* Establish *a Surcharge for the Recovery of Cost,* Case No. 9208, Order Nos. 83410 at 27-31 and 83531 at 32-41 (2010).

precludes the full-context analysis of costs and revenues that has always ensured that rates are just and reasonable. This is not to say we will never allow surcharges or other recovery mechanisms under any circumstances – as we pointed out in the BGE AMI cases, we have authorized surcharge recovery for certain kinds of program costs, such as energy efficiency and demand response programs that do not build utility infrastructure.[53]

To the extent new and different circumstances might persuade us to deviate from the principles that have driven our recent decisions not to allow infrastructure surcharges, we would need a fully developed record and an appropriate opportunity to test the facts and the parties' arguments before we could reach such a conclusion. And we would need to work through the myriad implications of such a switch. For example, the regulatory lag mechanisms Delmarva raised in this case could well be found, if we adopted them, to change the Company's risk profile, which in turn could alter the rate of return that we should authorize. Put another way, this is not a policy shift that we would ever be inclined to make through a settlement. So although we are content to approve the provisions in the Settlement convening the Regulatory Lag Work Group and allowing the parties to file with us the results of their efforts, we do so because they do not purport to require us to implement any regulatory lag mechanisms on this posture or to compel us, outside of the context of a new rate case, to address Delmarva's regulatory lag concerns at all. We may or may not do anything with the fruits of the work group's labors, but we pledge to review them carefully and thoughtfully, and it may well be that the ongoing dialogue on regulatory lag will benefit from the focused discussion the Settlement directs.

Finally, we wish to clarify our understanding regarding the operation of Settlement provision No. 6(c), which requires the Company in its next rate case filing to

[53] *Id.,* Order No. 83410 at 27-31.

provide both a zero intercept and a minimum system cost of service study. In the Company's last rate case, we declined to accept Staff's proposal for such studies, noting that the scope and cost were uncertain and that Staff had not demonstrated the need for the studies; we said, however, that we were open to the possibility of further study at a later time.[54] In this Settlement, the parties have agreed that the Company will conduct these studies, and Staff witness VanderHeyden noted that the studies will provide additional information for future cost of service analyses.[55] For those reasons, we will approve the Settlement and direct the Company to proceed with the studies. That said, we do not want this approval to be read as a decision to accept or adopt the results of such studies – we will, of course, study them at that time, along with the parties' analyses and arguments, and the Company should complete the studies before it files its next rate case so that we have them before us the next time cost of service studies are before us. We also accept the representation that the pair of studies can be done for $50,000 or less, but we direct the Company to notify us promptly if it expects the cost to exceed that figure. If that happens, we will review anew whether to require both studies based on the new cost estimates.

Having reviewed the record in this case, the Settlement and the testimony in support of it, the Commission finds that the Settlement is consistent with the public interest, and we therefore approve it. We find that the $12.2 million increase in distribution rates, which is to be apportioned according to provision No. 4 of the Settlement, will result in just and reasonable rates for all rate classes. And with the

[54] *Re Delmarva Power and Light Company,* Case No. 9192, Order No. 83085, 100 MD PSC 435, 458 (2009).
[55] VanderHeyden at 3-4.

understandings and clarifications set forth above, we approve the remaining provisions of the Settlement and direct the parties to proceed.

IT IS THEREFORE, this 8th day of July, in the year Two Thousand and Eleven, by the Public Service Commission of Maryland,

ORDERED: 1) The Application of Delmarva Power & Light Company, filed on December 21, 2010, seeking to increase electric distribution rates by $17,803,000 in its Maryland service territory is hereby denied;

2) The Joint Motion for Approval of Agreement of Unanimous Stipulation and Settlement is granted;

3) The Company shall file new tariffs that increase rates by no more than $12.2 million, consistent with Settlement provision No. 4 and effective with service provided on or after the date of this Order, which shall be subject to Commission Staff verification and Commission acceptance; and

4) A Phase II proceeding is hereby established pursuant to the terms of the Settlement and the terms of this Order.

/s/ Douglas R.M. Nazarian

/s/ Harold D. Williams

/s/ Susanne Brogan

/s/ Lawrence Brenner

Commissioners

delmarva power

A PHI Company

Douglas E. Micheel
Assistant General Counsel

EP1132
701 Ninth Street, NW
Suite 1100, 10th Floor
Washington, DC 20068

202 872-2318
202 331-6767 Fax
demicheel@pepcoholdings.com

December 9, 2011

Mr. David Collins
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202-6808

Re: Case No. 9249

Dear Mr. Collins:

Enclosed please find 17 (five three-holed punched) copies of Delmarva Power & Light Company's ("Delmarva Power") Distribution Studies prepared by Management Applications Consulting Inc. As part of the Joint Motion for Approval of Agreement of Unanimous Stipulation and Settlement, approved by the Commission in Order No. 84170, Delmarva Power agreed to conduct Minimum Distribution System and Zero-Intercept studies. It should be noted that Delmarva Power does not support or endorse the use of these methods for determining the cost of service.

Please contact me if you have any further questions.

Sincerely,

Douglas E. Micheel

DEM/mda

Enclosure

cc: All Parties of Record

Pepco Holdings, Inc

DELMARVA POWER & LIGHT COMPANY OF MARYLAND

Distribution Studies

Prepared by:

MAC

MANAGEMENT APPLICATIONS CONSULTING, INC.
1103 Rocky Drive – Suite 201
Reading, PA 19609
Phone: (610) 670-9199 / Fax: (610) 670-9190

MANAGEMENT APPLICATIONS CONSULTING, INC.

1103 Rocky Drive • Suite 201 • Reading, PA 19609-1157 • 610/670-9199 • fax 610/670-9190 •www.manapp.com

December 6, 2011

Mr. Elliott P. Tanos
Manager, Cost Allocation
Pepco Holdings, Inc.
P. O. Box 9239
Newark, DE 19714-9239

RE: Minimum Distribution System Studies

Dear Mr. Tanos:

Transmitted herewith are the results of the 2011 Minimum Distribution System studies for the Delmarva Power & Light Company of Maryland. On behalf of MAC, we appreciate the opportunity to prepare these analyses.

Should you require any additional information or assistance, please contact us.

Best regards,

Debbie L. Gajewski
Managing Consultant

Paul M. Normand
Principal

Enclosure

DELMARVA POWER & LIGHT COMPANY OF MARYLAND
DISTRIBUTION STUDIES

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DELMARVA POWER & LIGHT COMPANY OF MARYLAND

DISTRIBUTION STUDIES

DELMARVA POWER & LIGHT COMPANY OF MARYLAND
DISTRIBUTION STUDIES

I. Executive Summary

In 2011 Delmarva Power & Light Company of Maryland (Company) litigated Public Service Commission of Maryland case number 9249. As part of the rate case stipulation in that case, Delmarva agreed to file the results of a minimum size system study and a zero-intercept. The purpose of performing a minimum distribution study (MDS) is to identify the portion of a distribution account's investment which represents an estimated minimum investment required to serve a nominal load at a customer's location, or a no load condition.

Management Applications Consulting, Inc. (MAC) was retained in August 2011 to assist the Company in the preparation of the minimum size system and zero-intercept studies. The following FERC Accounts were included in the minimum distribution study analyses: 364-Poles and Towers, 365-Overhead Conductors and Devices, 366-Underground Conduit, 367-Underground Conductors and Devices, and 368-Line Transformers.

Although the purpose of each MDS method is the same, the methodology and underlying data used to perform each study is quite different. The minimum size system method uses a mathematical approach and relies heavily on current installation costs to derive a minimum cost per unit for each type or size of equipment. The zero-intercept method uses a statistical approach and relies heavily on historical plant account data to derive a minimum cost per unit.

Gathering the data needed to prepare the MDS analyses can be a daunting task and there are often data limitations for the approaches used, as explained in the report. The Company's staff however obtained the data used within the studies from the continuing property records, the geospatial information system (GIS) and the work management information system (WMIS).

A general description of each methodology employed, the data utilized, and the final results of each account within each method are included as part of this report. A summary of results for each method is shown below in Table MDS-1.

We however caution against a simple application of these results and their allocation in a class cost of service study without further analysis as we have discussed in Section IV of this study.

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Table MDS-1 – Summary of Minimum Size System and Zero-Intercept Method Results

Minimum Size						
Account	Primary		Secondary		Transformer	
	Cust	Dem	Cust	Dem	Cust	Dem
364	66.92%	33.08%	47.89%	52.11%		
365	61.29%	38.71%	72.04%	27.96%		
366	45.50%	54.50%	23.35%	76.65%		
367	45.50%	54.50%	23.35%	76.65%		
368					50.54%	49.46%

Zero Intercept						
Account	Primary		Secondary		Transformer	
	Cust	Dem	Cust	Dem	Cust	Dem
364	13.86%	86.14%	19.76%	80.24%		
365	13.86%	86.14%	19.76%	80.24%		
366	25.00%	75.00%	25.00%	75.00%		
367	25.00%	75.00%	25.00%	75.00%		
368					10.73%	89.27%

Primary/Secondary Weighting Factors		
Account	Primary	Secondary
364	72.72%	27.28%
365	87.83%	12.17%
366	86.52%	13.48%
367	86.52%	13.48%

Note: For the minimum size system analysis, the results for Account 367 are used as a proxy for Account 366. For the zero-intercept analysis, the results for Account 365 are also used as a reasonable proxy for Account 364. Finally, as explained in the report, estimates are provided as a proxy for Accounts 366 and 367 and, with data limitations, the results are considered to be underestimated.

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II. Comparison of Minimum System and Zero-Intercept MDS Methods

A. Theoretical Considerations

Two commonly used methods of determining the customer related portion of each account is the minimum size system approach and the zero-intercept approach. Both of these methods look at major items within an account to calculate the minimum cost also known as the customer related cost portion of the account.

1. Minimum Size System Method[1]

The first method, the minimum system method, assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customers. This method requires that the minimum size equipment (pole, conductor, and line transformer) be determined. The minimum size can be based on the minimum size installed on the system, the minimum size currently being installed, or the minimum size available from a supplier.

In determining the minimum size of each type of equipment, four considerations should be made. First, consider if the minimum size meets legal codes. Second, consider whether the minimum is realistic for all class of services. Third, consider if the minimum size item is a realistic item to be installed. Fourth, consider how often the selected minimum equipment item is used.

2. Zero-Intercept Method[2]

The second method, the zero-intercept method, uses a statistical calculation to determine the amount of distribution costs that could be classified as customer related. This method is based on the concept that there is a portion of plant related to a hypothetical no load or zero-intercept situation. The zero-intercept method attempts to calculate the customer related cost by extrapolating a regression curve to the y-intercept of a xy-coordinate plane (size versus cost per unit) for each of the distribution accounts. This method requires the use of statistical data which includes unit sizes, average costs per unit, and the number of units included in each account.

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[1] Discussions about the minimum size system and zero-intercept methods are excerpted from the *NARUC Electric Utility Cost Allocation Manual* (1992) and from the *Principals of Public Utility Rates* (1961) by James Bonbright.
[2] Ibid.

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The zero-intercept method is considered by many analysts to be the most accurate method since it is theoretically a more sound way of identifying only the customer portion of distribution costs by eliminating the load component. Unfortunately, because of its use of more data and statistical calculations, it is usually a less desirable method.

B. Criticisms of Minimum Distribution Studies

Minimum distribution studies attempt to classify distribution plant investment into customer and demand related cost components. Often these studies lead to a misclassification or misallocation to customer classes due to the shortcomings associated with employing a MDS. The actual amount of demand capability within the minimum size system is a function of load density, minimum required clearances, minimum equipment standards and standardization, temperature, and other engineering considerations. In addition, the number of customers being served varies with the level of service and the type of equipment being used by the customers.

The major criticisms concerning the MDS methods are as follows:

1. Minimum Size System Method[3]

There are two major criticisms associated with the use of the minimum system method. The first criticism is that the selection of the minimum size is largely judgmental. The customer related costs can vary significantly with the choice of method used to identify the minimum sized equipment. A method based on historical practice, current practice, or minimum available from a supplier (as long as it meets safety requirements) can all produce different minimum costs and resulting customer cost percentages of the total account(s).

The second criticism is that this method fails to recognize that even a minimum size distribution system has the capability to carry load that can be considered demand related. Depending on the selected minimum size and customer class, the equipment capability can fully serve a customer's load portion as well. If adjustments are not made to the allocation factors to reflect this load capability, the use of this method will lead to a disproportionate share of demand related costs being allocated to certain customers (i.e. "double dipping").

[3] *NARUC Electric Utility Cost Allocation Manual*, January 1992, Page 95.

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2. Zero-Intercept Method[4]

Although the zero-intercept method can be a more exact method due to its theoretic approach, it is often less desirable to use. The reasons this method is less desirable is because it requires the use of much more extensive data, an understanding of statistics, careful interpretation of the results which is a much more time consuming and expensive process.

Opponents of the zero-intercept method often present two major criticisms. The first is the zero-intercept method ignores the fact that a weak correlation exists between area and mileage of a distribution system and the number of customers served by the distribution system. In other words, it makes no allowance for customer density.

The second criticism is the zero-intercept method can often times produce statistically unreliable results such as negative or unreasonable cost. Unreliable results may occur due to questionable accounting data or abnormalities within the data. In many analyses, the data has to be reviewed and data points eliminated (outliers) in order to achieve meaningful results.

In Section IV of this report we provide general guidelines to consider when incorporating either of the MDS methods discussed above in a class cost of service study. The use of these guidelines will greatly reduce the allocation inequities that have plagued the historical use of these methods.

[4] Ibid.

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III. Description of Distribution Studies

The information required for the minimum size system and the zero-intercept distribution studies were provided by a number of departments within the Company. The Company's Engineering Standards department determined the minimum size items currently being installed for the electric distribution plant. The Company's Asset and Project Accounting department provided annual historical electric distribution plant investment data. The Company's Business Systems Department provided 2 years of historical electric distribution additions to plant investment data. The Company's Distribution Planning and Scheduling Department provided cost estimates for various residential and general service secondary customer installations.

A. Data Preparation

1. Minimum Size System

The following steps were taken to prepare the FERC accounts 364 through 368 data from the Company's database systems to be used in the study:

- Company staff from the Engineering Standards department provided the minimum system size units to be used in the study.
- The number of poles by size, lengths of overhead conductors by primary and secondary footage, lengths of underground conduit by footage, and the number of line transformers were provided.
- The average unit cost for the minimum size equipment and other currently installed unit types were provided. These unit prices were used to calculate a 2010 dollar total cost and a 2010 dollar minimum cost.
- The footage associated with the unit costs for the currently installed equipment for plant accounts 365 and 367 were used in the calculation of the customer costs.
- Plant account 364 poles were assigned to primary and secondary voltages based on the following assumptions: poles greater than 40 feet were classified as primary, poles less than 40 feet were classified as secondary, and 40 foot poles were allocated to primary and secondary based on a circuit equivalent footage of primary and secondary overhead conductors (72.72% primary and 27.28% secondary).

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2. Zero-Intercept

The following steps were taken to prepare the FERC accounts 364 through 368 data from the Company's accounting database to be used in the study:

- Staff from the Company's Asset and Project Accounting department queried the Continuing Property Records database for Delmarva Power and Light Company's Maryland electric distribution accounts 364 through 368 to gather the historical accumulated costs and number of units associated with these costs.

- Information from the Handy Whitman Index for electric distribution plant accounts 364 through 368 for the years 1970 to 2010 was used to index the original plant investment to a 2010 constant dollar level, thus eliminating the inflation of the units over time.

- The unit cost (investment cost divided by the number of units) in 2010 constant dollars was calculated for each vintage, material type/size of equipment.

- Cost per unit for each vintage, material type/size was visually inspected for outliers or values that seemed to be erroneous. These outliers were excluded from the analysis.

- For each account, total 2010 constant dollar investment, total number of units, and cost per unit by type/size were calculated. In addition, all type/size investment and number of units within each account was summed.

- Overhead and underground conductor types and lengths were provided by primary and secondary voltages. These types and lengths were subtotaled into the same conductor groups for which the historical data was provided.

- The overhead and underground conductor types and lengths were analyzed and an appropriate ampacity was assigned to each group.

B. Minimum Size System Method Study

1. Methodology Employed

The minimum sized equipment used in the preparation of the study was based on the minimum size equipment currently being installed on the Company's system. Minimum sizes were determined and provided by the Engineering Standards

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department. Equipment types along with their associated ampacity rating, quantities, and current unit costs were identified and included as part of the study.

The minimum or customer related cost for each account was calculated as follows:

1. 2010 Total Account Cost = Average current cost of each unit * Number of units of each type.
2. Customer related cost = Average minimum current cost * Number of each unit type.
3. Customer related percentage = Customer related cost / Total 2010 Total Account Cost.
4. Demand related cost = Total Account Cost – Customer related cost.
5. Demand related percentage = Demand related cost / Total Account Cost.

Note: The use of the minimum size equipment currently being installed will generally derive higher customer related portions of plant accounts.

2. Account 364 - Poles, Towers and Fixtures

The number of poles by type and vintage was provided through a query of the Company's GIS. The minimum size primary pole is 40 feet and the minimum size secondary pole is 30 feet. A current unit cost for each the minimum primary and secondary pole was provided by the Engineering Department from a query of the Work Management Information System (WMIS). The results for Account 364 are included below in Table MDS-2.

Account 364 - Primary

Primary poles were considered to be 72.72% of the 40 foot poles and all poles greater than 40 feet. The quantities of the primary pole types were multiplied by its unit cost to calculate the $2010 total primary account costs. The quantities of primary pole types were then multiplied by the minimum 40 foot primary pole unit cost of $287.97 to calculate the customer related costs for the primary portion of Account 364. This customer related cost is divided by the $2010 total primary account costs to derive the customer percentage of 66.92%. The balance of the account is classified as demand related costs for the account.

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Account 364 - Secondary

Secondary poles were considered to be 27.28% of the 40 foot poles and all poles less than 40 feet. The quantities of the secondary pole types were multiplied by its unit cost to calculate the $2010 total secondary account costs. The quantities of secondary pole types were multiplied by the minimum 30 foot secondary pole unit cost of $101.97 to calculate the customer related costs for the secondary portion of Account 364. This customer related cost is divided by the $2010 total secondary account costs to derive the customer percentage of 47.89%. The balance of the account is classified as demand related costs for the account.

3. **Account 365 - Overhead Conductors and Devices**

The footage for overhead conductors by type and voltage level was provided by the Company. A subset total of 19,286,210 feet of primary overhead conductor and 1,768,554 feet of secondary overhead conductor were used in the calculation. The minimum primary conductor being installed is type 1/0 AAC. The minimum secondary conductor type is #2 Aluminum Triplex. The results for Account 365 are included below in Table MDS-2.

Account 365 - Primary

The footage of the primary conductor types was multiplied by its unit cost to calculate the $2010 total primary portion of the account costs. The footage of each type of primary conductor was multiplied by the minimum current installed conductor unit cost of $1.54 per foot to calculate the customer related primary cost component. This customer related account cost is divided by the $2010 total primary portion of the account costs to derive the customer related percentage of 61.29%. The balance of the account is classified as demand related costs.

Account 365 - Secondary

The footage of the secondary conductor types was multiplied by its unit cost to calculate the $2010 total secondary portion of the account costs. Each type of secondary conductor's footage was multiplied by the minimum current conductor unit cost of $1.37 per foot to calculate the customer related secondary cost component. This customer related account cost is divided by the $2010 total secondary portion of the account costs to derive the customer related percentage of 72.04%. The balance of the account is classified as demand related costs.

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4. **Account 366 - Underground Conduits**

Due to the aggregated nature of the detail for this account, a minimum system calculation could not be performed. Account 367 is used as a proxy for this account.

5. **Account 367 - Underground Conductors and Devices**

The footage for underground conductors by type and voltage level was provided by the Company. A subset total of 10,573,786 feet of primary overhead conductor and 1,480,246 feet of secondary underground conductor were used in the calculation. The minimum primary conductor being installed is type 1/0 Solid Aluminum. The minimum secondary conductor type is 1/0 Aluminum Triplex. The results for Account 367 are included below in Table MDS-2.

Account 367 - Primary

The footage of the primary conductor types was multiplied by its unit cost to calculate the \$2010 total primary portion of the account costs. Each type of primary conductor's footage is multiplied by the minimum current conductor unit cost of \$3.39 per foot to calculate the customer related primary cost. This customer related account cost is then divided by the \$2010 total primary portion of the account costs to derive the customer related percentage of 45.50%. The balance of the account is classified as demand related costs.

Account 367 - Secondary

The footage of the secondary conductor types was multiplied by its unit cost to calculate the \$2010 total secondary portion of the account costs. Each type of secondary conductor's footage is multiplied by the minimum current conductor unit cost of \$1.42 per foot to calculate the customer related secondary cost. This customer related account cost then is divided by the \$2010 total secondary portion of the account costs to derive the customer related percentage of 23.35%. The balance of the account is classified as demand related costs.

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6. Account 368 – Line Transformers

Company data for line transformers is maintained by KVA size. The minimum size line transformer is 25 KVA.

Each line transformer type was multiplied by its unit cost to calculate the $2010 total account costs. Each type of line transformer is multiplied by the minimum current line transformer unit cost of $944.00 to calculate the customer related cost. This customer related account cost is divided by the $2010 total account costs to derive the customer related percentage of 50.54%. The balance of the account is classified as demand related costs for the account. The results for Account 368 are shown below in Table MDS-2.

7. Table MDS-2 – Minimum Size Method Results

	Classification	Plant Accounts				
		364	365	366	367	368
1	**Primary**					
2	Customer	66.92%	61.29%	45.50%	45.50%	
3	Demand	33.08%	38.71%	54.50%	54.50%	
4	**Secondary**					
5	Customer	47.89%	72.04%	23.35%	23.35%	
6	Demand	52.11%	27.96%	76.65%	76.65%	
7	**Transformer**					
8	Customer					50.54%
9	Demand					49.46%

Note: Account 367 results are used as a proxy for Account 366.

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C. Zero-Intercept Method Results

1. Methodology Employed

The zero-intercept studies statistical analysis and graphics were performed using the Excel Data Analysis linear regression. A simple linear regression attempts to determine the relationship between two variables by fitting a straight line to the data that minimizes the errors in predicting the dependent variable by using the independent variable. The algebraic expression for simple linear regression model is:

y = ***B0*** + ***B1x***; *where:*

- *y* = *the dependent variable or variable to be predicted (in this case cost per foot or unit)*
- *x* = *the independent variable or variable that will be used as a predictor of y (in this case ampacity rating or transformer size)*
- *B0* = *the y-intercept or zero-intercept of the line; (in this case the point at which the regression line crosses the y-axis at an ampacity rating of zero)*
- *B1* = *the slope of the line*

In this analysis, the point where the regression line crosses the "Y" axis identifies the cost per foot of a conductor with a rating of zero amps on the "X" axis (zero load). The criterion utilized in selecting the best regression model is as follows:

- Review R-Squared (also known as coefficient of determination) value to determine the predictive power of the model. The R-Squared is an indication of how well the dependent variable (cost per foot) is in predicting the independent variable (conductor ampacity) using an ordinary-least squares (OLS) approach. The larger the value the better the regression line describes the data.

- Select a model with statistically significant regression coefficients. These include the standard errors, t-statistic at 95 percent confidence bounds of the parameter estimates.

- Select a model with a regression line that provides a good fit for the data. This is a slightly more subjective criterion in that it is based somewhat on experience and informed judgment.

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2. Account 364 - Poles, Towers and Fixtures

Company historical data for account 364 is maintained and available for only two pole groups: <=45' and >45'. A statistical analysis could not be performed due to a lack of account detail. The results of Account 365 are used as a reasonable proxy for this account.

3. Account 365 - Overhead Conductors and Devices

Historical Company data for overhead conductors is maintained in six aggregated groups as shown below. Since the overhead conductors were listed in ranges, an ampacity estimate was assigned to each type based on an analysis of the quantities and type of conductors included in each group. The ampacity ratings are shown below in Table 1.

Table 1 - Description of Conductor Ampacity Estimates

	Ampacity	
Conductor Type	Primary	Secondary
1 CU <= 1	144	144
1/0 AL/ACSR <= 1/0	257	248
1/0 CU >= 1/0 and < 477 MCM	310	264
2/0 AL/ACSR >= 2/0 and <= 477 MCM	453	408
477 MCM >= 477 Al. and Cu.	713	699
TRI/QUAD All Sizes		203

Straight line linear regression models were developed using ampacity as the independent variable and cost per foot as the dependent variable. Results for the straight line regression models are shown below in Tables 2 through 4, and in Graph 1 below.

The straight-line regression models yielded regression models with an R Square of 78.3% for primary and 71.3% for secondary as shown in Table 2 below.

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Table 2 – Summary Statistics Straight Line Regression Models

Regression Statistics	Primary	Secondary
Multiple R	0.8850026	0.8441954
R Square	0.7832297	0.7126659
Adjusted R Square	0.7109729	0.6168878
Standard Error	0.9474939	1.0908628
Observations	5	5

Table 3 – ANOVA Results Straight Line Regression Models

ANOVA - Primary

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	9.73113293	9.73113293	10.8395321	0.04599693
Residual	3	2.69323422	0.89774474		
Total	4	12.4243671			

ANOVA - Secondary

	df	SS	MS	F	Significance F
Regression	1	8.85442245	8.85442245	7.44080641	0.07207504
Residual	3	3.56994469	1.18998156		
Total	4	12.4243671			

In addition, both regression coefficients, the ampacity and the zero-intercept, were statistically significant, as is shown in Table 4 below.

Table 4 – Summary Coefficients Straight Line Regression Models

Primary	*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Intercept	0.4853561	0.9162292	0.5297322	0.6329970
Ampacity	0.0071224	0.0021633	3.2923445	0.0459969

Secondary	*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Intercept	0.7229750	1.0179014	0.7102603	0.5287768
Ampacity	0.0069114	0.0025337	2.7277842	0.0720750

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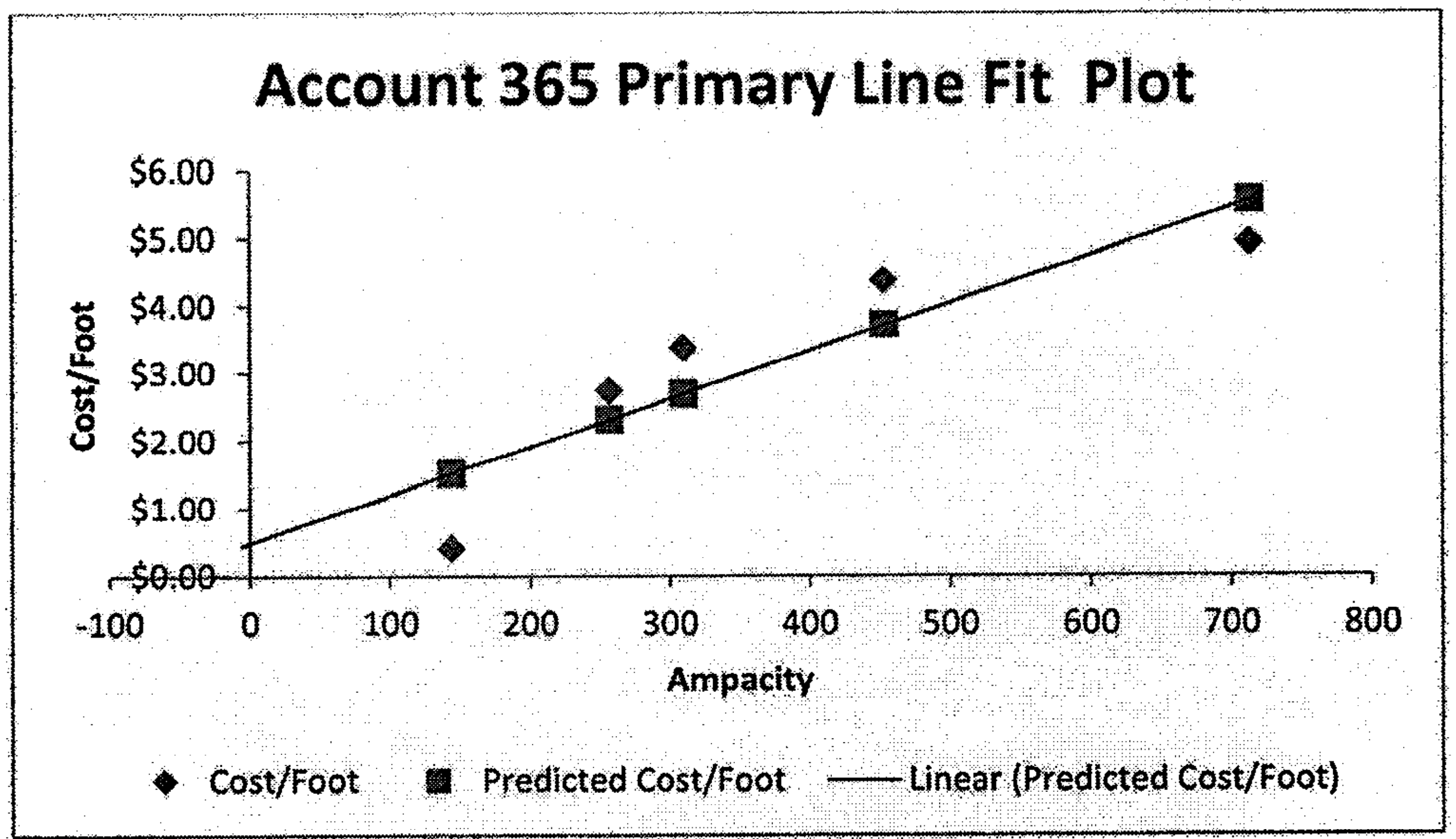
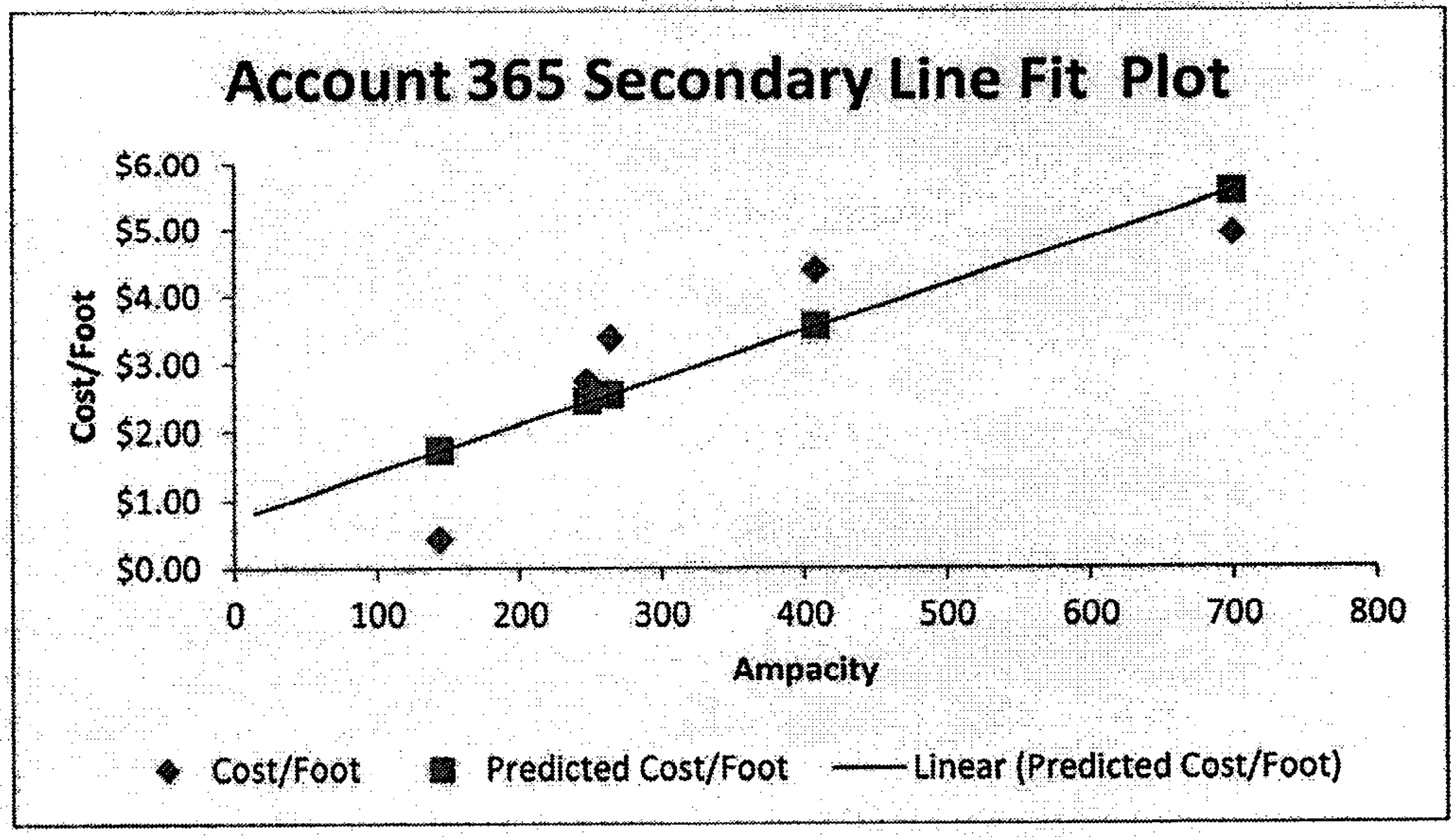
Graph 1 – XY Scatterplot – Straight Line Regression for Account 365





The cost per foot for the primary overhead conductors is $0.49 as shown above in Table 4. The customer related primary conductor cost is calculated by multiplying the unit cost of $0.49 by the number of primary conductor feet. The primary customer cost is divided by the primary portion of the account balance to derive the primary customer related percentage of 13.86%. The remaining balance of the primary account is then classified as demand related costs.

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The customer related secondary conductor cost is calculated by multiplying the unit cost of $0.72 by the number of secondary conductor feet. The secondary customer cost is divided by the secondary portion of the account balance to derive the secondary customer related percentage of 19.76%. The remaining balance of the primary account is classified as demand related costs. The results for Account 365 are included below in Table MDS-3.

In analyzing the primary scatter plot of the data in the Graph 1 section above, the primary zero-intercept is $0.49 which suggest that the Company's initial cost for each foot of primary at zero load (ampacity).

In analyzing the secondary scatter plot of the data in the Graph 1 section above, the secondary zero-intercept of $0.72 suggest that the Company's initial cost for each foot of secondary at zero load (ampacity).

4. Account 366-Underground Conduit

Company historical data for account 366 is not available in sufficient detail for this study. Therefore, a statistical analysis could not be performed. The results for Account 367 are used as a reasonable proxy for this account.

5. Account 367 - Underground Conductors and Devices

Historical Company data for underground conductors is maintained in three aggregated groups. The third group was partitioned to only consider a reasonable portion of the primary and secondary installed conductors. Since the underground conductors were listed in ranges, an ampacity estimate was assigned to each type based on a review of the quantities and type of conductors included in each group. The selected ampacity ratings are shown below in Table 5.

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Table 5 - Description of Conductor Ampacity Estimates

	Ampacity	
Conductor Type	Primary	Secondary
# 1 >= # 12 Cable	180	264
#1/0 >= #4/0 Cable	280	421
#300 <= #500	769	
#250 <= #350		707

Straight line linear regression models for primary and secondary were developed using ampacity as the independent variable and unit cost per foot as the dependent variable. Results for the straight line regression model are shown below in Tables 6 through 8, and in Graph 2.

The straight-line regression models yielded a regression model with a very good explanatory power (R Square of 98.72% for primary and 93.85% for secondary) but the application of these results in any meaningful way is unacceptable as shown in Table 6 below.

Table 6 – Summary Statistics Straight Line Regression Model

Regression Statistics		
	Primary	Secondary
Multiple R	0.9935629	0.9687661
R Square	0.9871672	0.9385078
Adjusted R Square	0.9743343	0.8770156
Standard Error	3.3209584	3.1457334
Observations	3	3

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Table 7 – ANOVA Results Straight Line Regression Models

ANOVA - Primary					
	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	848.388650	848.38865	76.9250828	0.07227278
Residual	1	11.0287649	11.0287649		
Total	2	859.417415			
ANOVA - Secondary					
	df	SS	MS	F	Significance F
Regression	1	151.029464	151.029464	15.2622248	0.15953097
Residual	1	9.89563881	9.89563881		
Total	2	160.925103			

In addition, both regression coefficients, the ampacity and the zero-intercept, were not statistically significant, as is shown in Table 8 below.

Table 8 – Summary Coefficients Straight Line Regression Models

Primary	*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Intercept	-13.0251967	3.6056739	-3.61241672	0.17192569
Ampacity	0.06540068	0.00745673	8.77069455	0.07227278

Secondary	*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Intercept	-10.994897	4.93972332	-2.22581232	0.26881281
Ampacity	0.03867224	0.00989898	3.90668975	0.15953097

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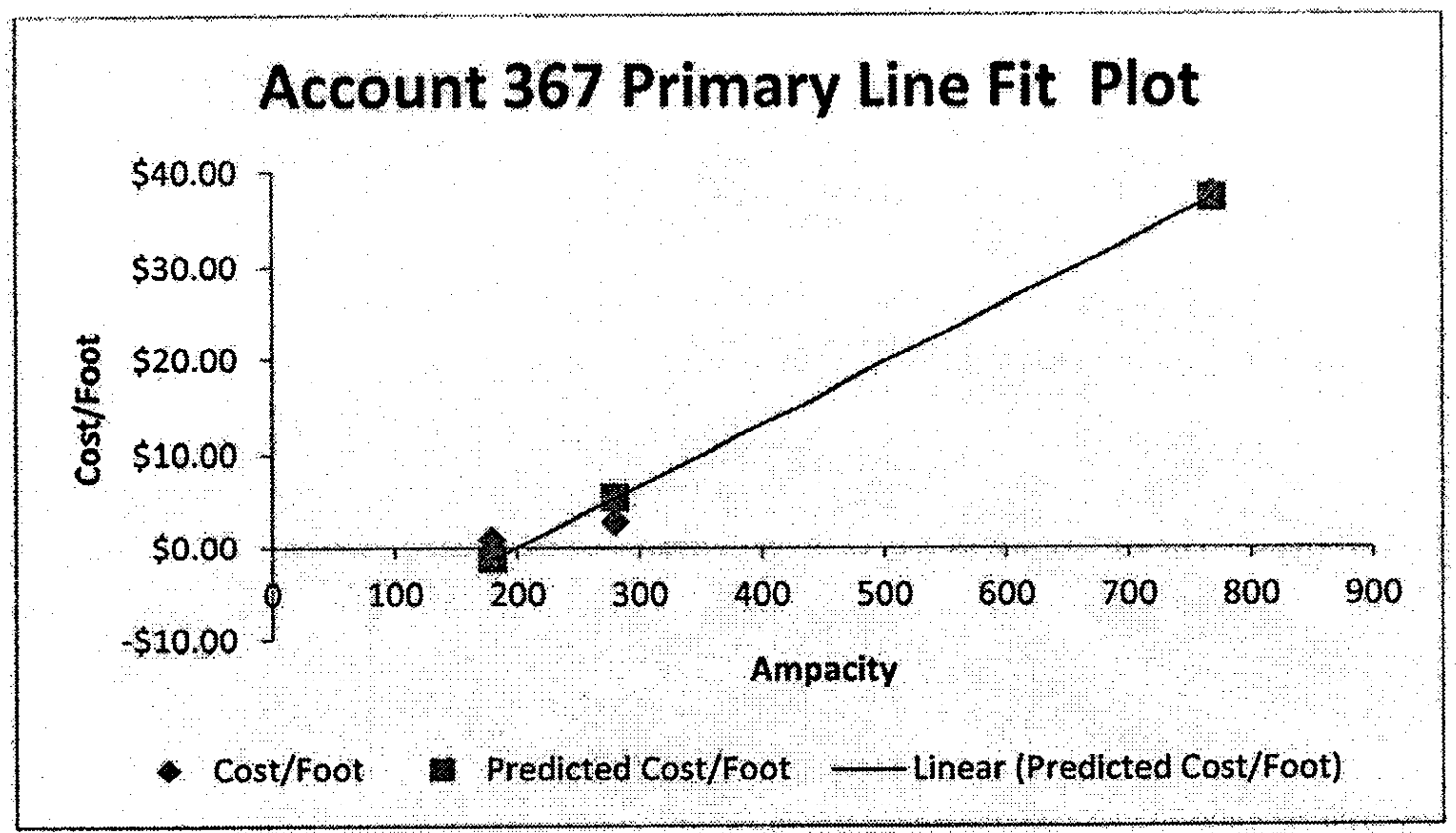
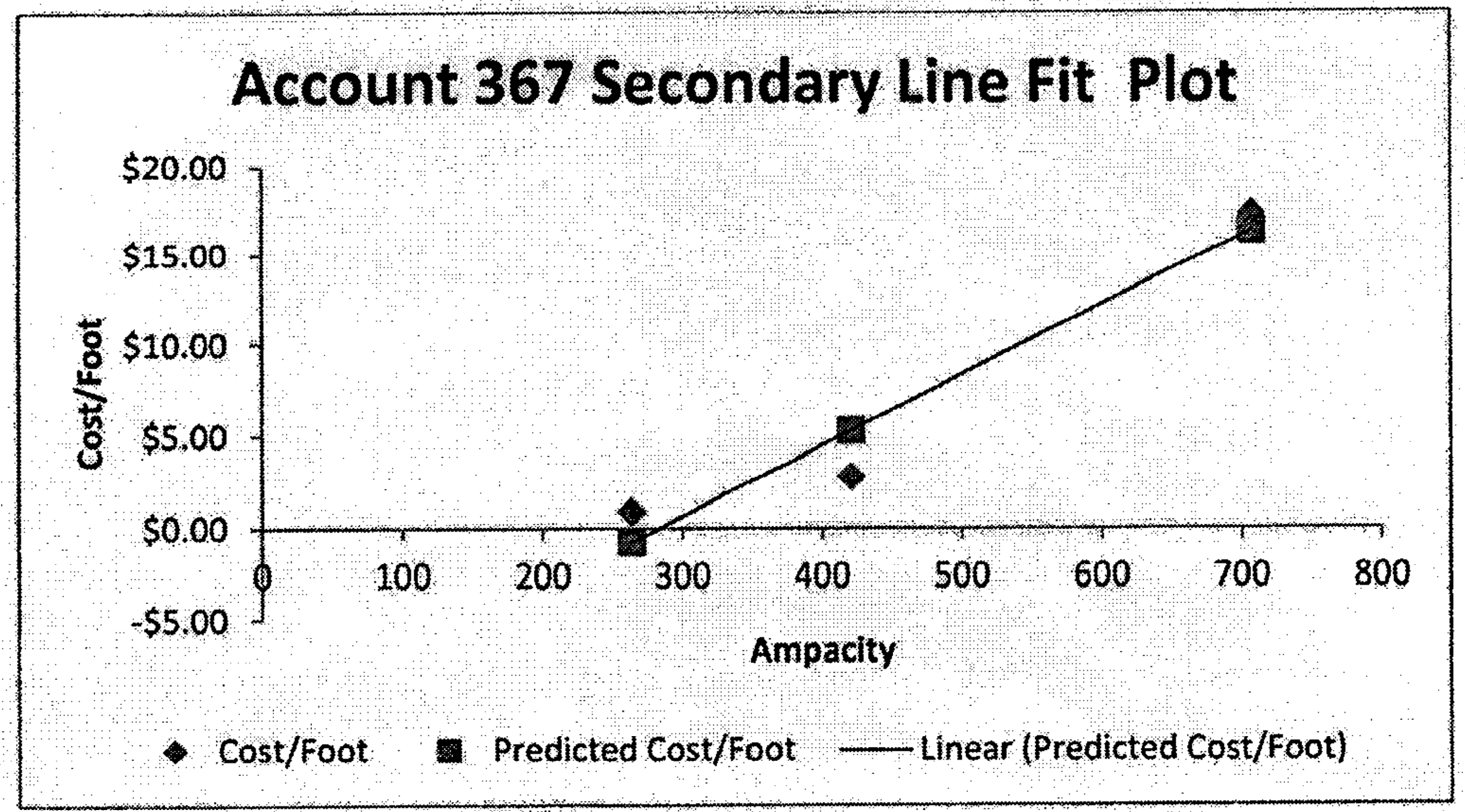
Graph 2 – XY Scatterplot – Straight Line Regression for Account 367





In analyzing the scatter diagram of the data in Graph 2 above, as well as the other statistics it is determined that the results from the zero-intercept should not be used. As a proxy, a customer-related percentage of 25.00% was estimated for both primary and secondary. The remainder of the account is demand-related.

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6. Account 368 – Line Transformers

Historical Company data for line transformers was provided by KVA. Each KVA type was analyzed separately and unit costs per transformer type were calculated based on the data provided. The transformer ratings are shown below in Table 9.

Table 9 - Description of Transformer KVA Estimates

KVA Rating
3
5
10
15
25
37.5
50
75
100
150
167
225
250
300

A straight line linear regression model was developed using KVA as the independent variable and cost per transformer as the dependent variable. Results for the straight line regression model are shown below in Tables 10 through 12, and in Graph 3.

The straight-line regression model for the transformers yielded a regression model with very good explanatory power (R Square of 93.3%).

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Table 10 – Summary Statistics Straight Line Regression Model

Transformer Regression Statistics	
Multiple R	0.9660007
R Square	0.9331573
Adjusted R Square	0.9275871
Standard Error	2779.41759
Observations	14

Table 11 – ANOVA Results Straight Line Regression Model

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1294166137	1294166137	167.526081	2.0723E-08
Residual	12	92701945.9	7725162.16		
Total	13	1386868083			

In addition, regression coefficients, the KVA and the zero-intercept, were statistically significant, as is shown in Table 12 below.

Table 12 – Summary Coefficients Straight Line Regression Model

Transformer	*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Intercept	595.211896	1072.24863	0.55510623	0.58902023
KVA	99.1978526	7.66409813	12.9431866	2.0723E-08

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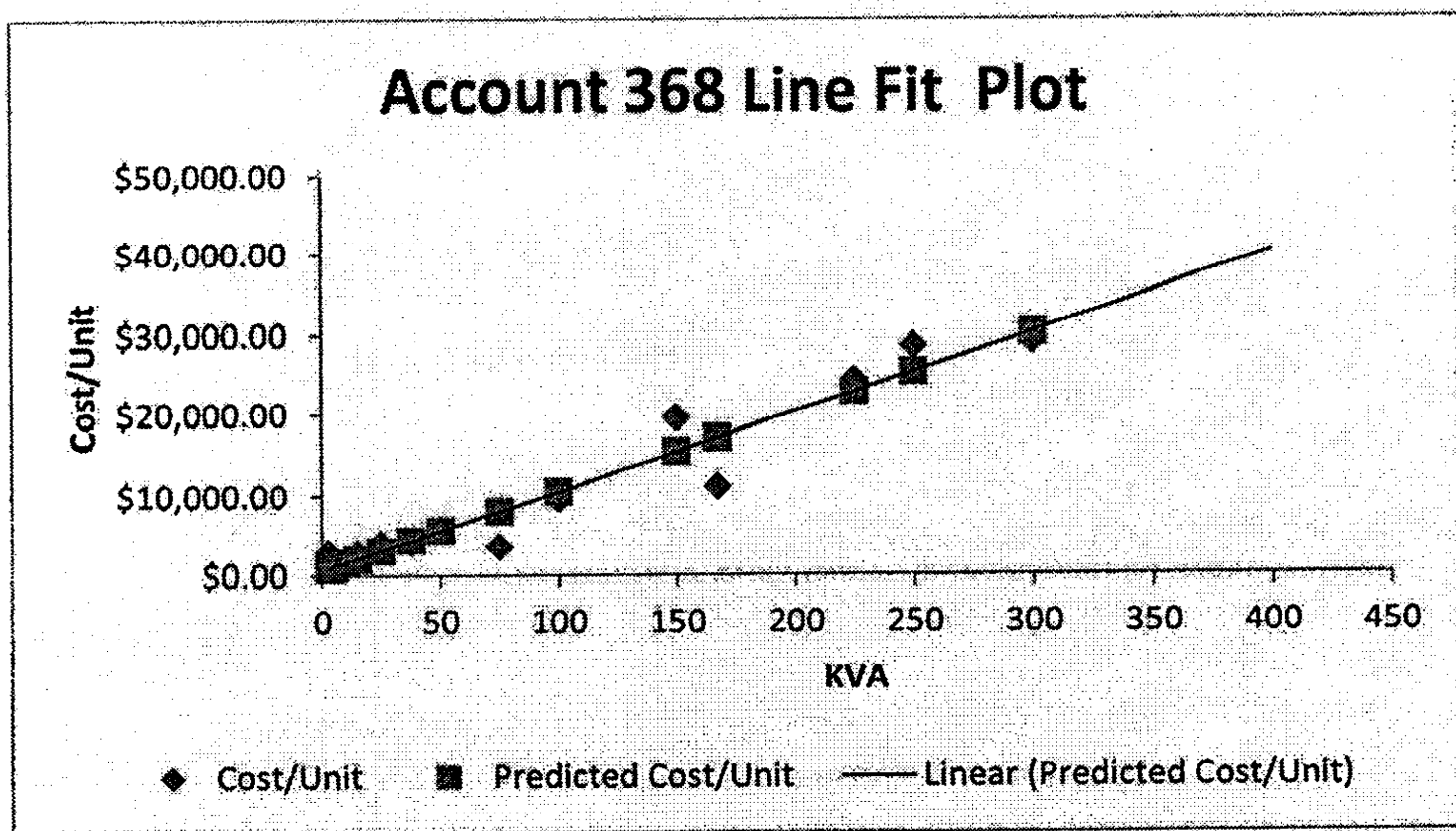
Graph 3 – XY Scatterplot – Straight Line Regression for Account 368



The cost for a line transformer is $595.21 as shown above in Table 12. The customer related cost is calculated by multiplying the unit cost of $595.21 by the number of line transformers. The balance of the account is classified as demand related costs. Customer and demand related percentages are calculated by dividing each of these costs by the historical plant constant dollar cost for the years 1970 through 2010. The results for Account 368 are included below in Table MDS-3.

In analyzing the scatter diagram of the data in Graph 3 above and Table 12 below, the zero-intercept is $595.21 which suggests that the zero load (KVA) cost is $595.21 per line transformer.

DELMARVA POWER & LIGHT COMPANY OF MARYLAND

DISTRIBUTION STUDIES

7. **Table MDS-3 – Zero-Intercept Method Results**

		Accounts				
		364	**365**	**366**	**367**	**368**
1	**Primary**					
2	Customer	13.86%	13.86%	25.00%	25.00%	
3	Demand	86.14%	86.14%	75.00%	75.00%	
4	**Secondary**					
5	Customer	19.76%	19.76%	25.00%	25.00%	
6	Demand	80.24%	80.24%	75.00%	75.00%	
7	**Transformers**					
8	Customer					10.73%
9	Demand					89.27%

Note: Due to a lack of data for the zero-intercept, Account 365 results are used as a proxy for Account 364. In addition, estimates are provided as a proxy for Accounts 366 and 367 since there is insufficient detail for these studies.

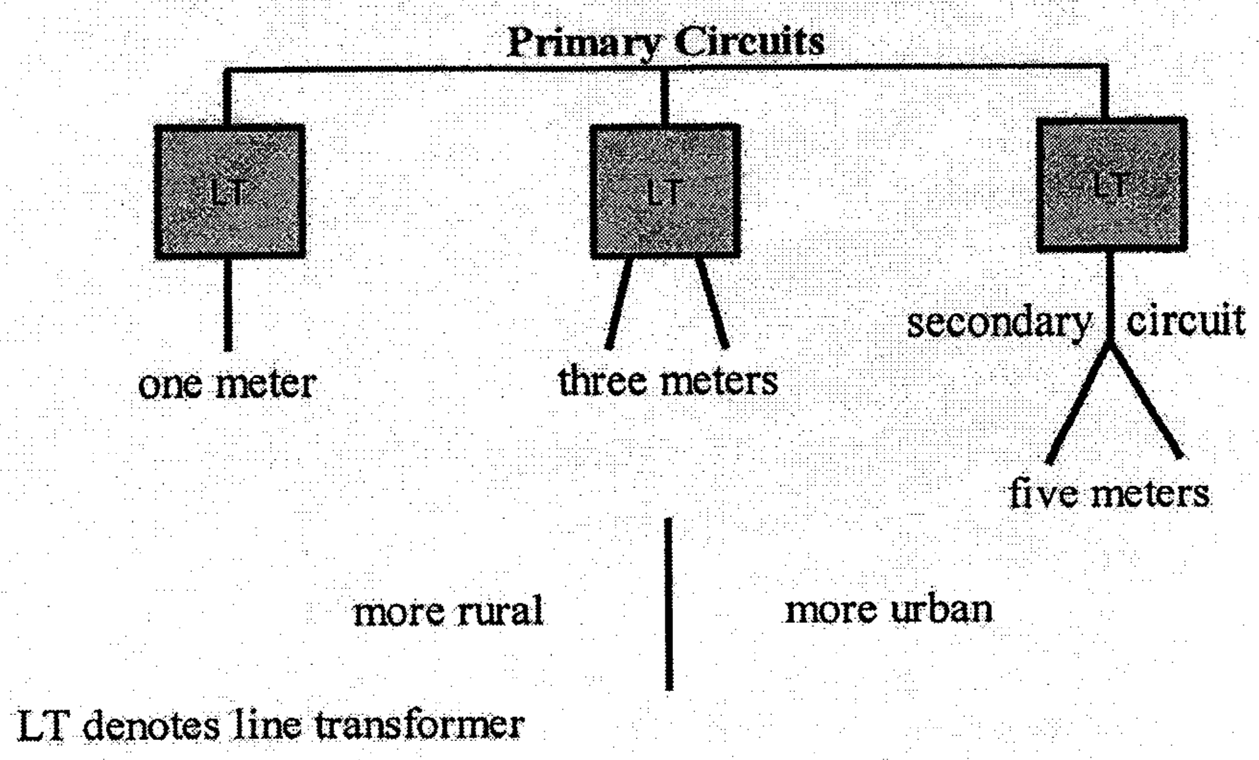
DELMARVA POWER & LIGHT COMPANY OF MARYLAND
DISTRIBUTION STUDIES

IV. Implementation of the MDS Results in Class Cost of Service Study

Distribution circuits and line transformer investment for the residential classes is typically a much larger investment relative to load than for larger commercial or industrial classes. However, the residential customers' load diversity is directly related to the number of customers and the area from which they are served (urban versus rural). The installed distribution facilities are able to take advantage of the smaller customer load diversity in making economic engineering distribution plant investments. For example, line transformers have typically between three to five smaller customers per installation versus one for each large customer. In order to properly recognize this customer concentration at any one location, the customer component must recognize this concentration in assigning cost using an MDS in a class cost of service study. If an adjustment is not made to allocation factors, the result will material overstate and "double dip" both the customer and demand cost categories. Recognizing basic installation practices in the allocation process is of paramount importance in equitably applying any MDS procedure as shown in Figure 1 below.

Figure 1

Distribution Secondary Circuits



DELMARVA POWER & LIGHT COMPANY OF MARYLAND
DISTRIBUTION STUDIES

A. Minimum Size System Method

The resulting customer and demand related percentages for each account are used to classify the distribution plant account dollars. These plant account dollars are then allocated to classes based on an appropriate cost causation factor. A customer allocation factor based on the number of customers in each class is typically used to allocate the customer portion of the account. However, this simplified customer allocation approach needs to be adjusted (reduced) for secondary circuits and line transformers to more appropriately reflect the customers being served from each type of equipment. This adjustment would be made to all the customer allocation factors used to allocate the secondary portion of Accounts 364-367 and Account 368.

The remaining demand portion of the account is typically allocated using a demand allocation factor. This demand allocation factor also needs to be adjusted to account for the load associated with the minimum system load carrying capability. These adjustments are necessary and required to properly correct the allocation of demand related costs since a large portion if not all of smaller customer load required are being met by the minimum size designation. Table 13 illustrates the recommended allocation factor adjustments starting point.

Table 13 – Minimum Size System Class Allocation

		Residential	General Service Secondary Small	General Service Secondary Large
1	**Accounts 364, 365, 366, & 367**			
2	Primary			
3	Customer	Use number of customers for all classes.		
4	Demand	Use class demands adjusted for losses for all classes.		
5	Secondary			
6	Customer	50% of customers	All customers	Customers < 150 kW
7	Demand	25% of demand	50% of demand	100% demand
8	**Account 368**			
9	Customer	No. of Customers / 3	No. Customers / 1.5	All customers
10	Demand	0% of demand	50% of demand	90% max demand

DELMARVA POWER & LIGHT COMPANY OF MARYLAND
DISTRIBUTION STUDIES

B. Zero-Intercept Method

As previously mentioned, the resulting customer and demand related percentages for each account are used to classify the distribution plant account dollars. These plant account dollars are then allocated to classes based on an appropriate cost causation factor. Since the zero-intercept method ignores the fact that a weak correlation exists between area and mileage of a distribution system and the number of customers served by the system, an adjustment must be made to reduce the number of secondary and line transformer customers included in the customer related allocation factor. This would include the customer allocation factors used to allocate the secondary portion of Accounts 364-367 and Account 368. Table 14 illustrates the recommended allocation factor adjustments starting point.

Table 14 – Zero-Intercept Class Allocation

		Residential	General Service Secondary Small	General Service Secondary Large
1	**Accounts 364, 365, 366, & 367**			
2	Primary			
3	Customer	Use number of customers for all classes.		
4	Demand	Use class demands adjusted for losses for all classes.		
5	Secondary			
6	Customer	50% of customers	25% of customers	customers < 150 kW
7	Demand	Use class demands adjusted for losses for all classes.		
8	**Account 368**			
9	Customer	No. of Customers / 3	No. Customers / 1.5	All customers
10	Demand	Class demands	Class demands	100% max demand

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Distribution Studies prepared by Management Applications Consulting Inc. for Delmarva Power & Light Company was sent by first-class mail, postage prepaid, on this 9th day of December to all parties in Case No. 9249.

David J. Collins
Executive Secretary
Office of the Executive Secretary
Public Service Commission Of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202-6806

Theresa V. Czarski, Esq.
Deputy People's Counsel
Office of People's Counsel
William Donald Schaefer Tower
6 St. Paul St., Suite 2102
Baltimore, MD 21202

Ronald Herzfeld, Esq.
Assistant People's Counsel
Office of People's Counsel
William Donald Schaefer Tower
6 St. Paul St., Suite 2102
Baltimore, MD 21202

Leslie M. Romine
Staff Counsel
Office of Staff Counsel
William Donald Schaefer Tower
6 St. Paul St., 17th Floor
Baltimore, MD 21202

Chuck L. McLean, Esq.
Staff Attorney
Office of Staff Counsel
William Donald Schaefer Tower
6 St. Paul St., 17th Floor
Baltimore, MD 21202

John W. Leonard, Esq.
DeCaro, Doran, Siciliano
Gallagher & DeBlasis
17251 Melford Blvd #200
Bowie, MD 20715

Christopher R. Dunn, Esq.
DeCaro, Doran, Siciliano
Gallagher & DeBlasis
17251 Melford Blvd #200
Bowie, MD 20715

Holly Rachel Smith
Holly Rachel Smith, PLLC
Hitt Business Center
3803 Rectortown Road
Marshall, VA 20115

Douglas E. Micheel

Delmarva Power & Light Company

Summary of Minimum Size System and Zero-Intercept Method Results

		Primary [1]		Secondary [1]	
Line	Account	Customer	Demand	Customer	Demand
		(1)	(2)	(3)	(4)
	Minimum Size Study Results:				
1	364	66.92%	33.08%	47.89%	52.11%
2	365	61.29%	38.71%	72.04%	27.96%
3	366	45.50%	54.50%	23.35%	76.65%
4	367	45.50%	54.50%	23.35%	76.65%
	Zero Intercept Study Results:				
5	364	13.86%	86.14%	19.76%	80.24%
6	365	13.86%	86.14%	19.76%	80.24%
7	366	25.00%	75.00%	25.00%	75.00%
8	367	25.00%	75.00%	25.00%	75.00%
	Average of Results:				
9	364	40.39%	59.61%	33.83%	66.18%
10	365	37.58%	62.43%	45.90%	54.10%
11	366	35.25%	64.75%	24.18%	75.83%
12	367	35.25%	64.75%	24.18%	75.83%

Sources:
[1] December 9, 2011 Delmarva Distribution Studies, Public Service Commission of Maryland, Case No. 9249.

Delmarva Power & Light Company
Delaware Retail Cost of Service Study
12 Months Ended December 31, 2012
Distribution Accounts 364 Through 367 Include Customer Classification

Line	Description	Total Delaware Distribution* (1)	Total Residential Service (2)	Total General Serv. Secondary (3)	Total General Serv. Primary (4)	Total General Serv. Transmission** (5)	Street Lighting Service (6)	Rate 1,2,6,7 Residential (7)	Rate 8,9 Residential Space Heat (8)	Rate 10,11,12,13,14 General Serv. Sec. Small (9)	Rate 16 General Serv. Sec. Large (10)	Rate 17,18,26 General Serv. Primary (11)	Rate 20,40 General Serv. Trans.** (12)	TRAFFIC LIGHTS (13)	Rate 21,25,30 Street Lighting Service (14)
	RATE BASE														
1	Total System Electric Distributio	1,105,826,419	715,647,742	202,641,603	103,776,564	1,057,993	82,702,517	485,727,411	229,920,331	153,194,837	49,446,766	103,776,564	1,057,993	297,933	82,702,517
2	Less: Depreciation Reserve	408,308,201	263,690,412	74,955,283	39,510,009	415,517	29,736,980	179,195,417	84,494,995	56,753,808	18,201,475	39,510,009	415,517	131,952	29,736,980
3	Total Net Plant	697,518,218	451,957,330	127,686,321	64,266,555	642,475	52,965,537	306,531,994	145,425,336	96,441,029	31,245,292	64,266,555	642,475	165,980	52,965,537
	ADD:														
4	CWIP	70,111,664	44,847,479	12,981,405	7,863,474	94,282	4,325,024	30,700,603	14,146,876	9,926,072	3,055,333	7,863,474	94,282	43,108	4,325,024
5	Working Capital	10,880,508	7,129,072	2,007,735	1,294,162	62,510	387,029	5,016,276	2,112,796	1,616,252	391,483	1,294,162	62,510	7,300	387,029
6	Materials & Supplies	18,160,007	11,762,872	3,324,684	1,667,840	16,575	1,388,036	7,974,852	3,788,019	2,509,101	815,583	1,667,840	16,575	4,167	1,388,036
7	Misc. Rate Base Items	57,326,981	36,121,595	10,763,760	8,007,142	111,134	2,323,350	25,084,238	11,037,357	8,392,063	2,371,697	8,007,142	111,134	65,868	2,323,350
	DEDUCT:														
8	Accumulated ITC	1,853,142	1,199,316	339,532	172,773	1,746	139,775	813,631	385,685	256,474	83,058	172,773	1,746	474	139,775
9	Customer Advances	1,650,908	1,071,958	301,575	145,089	1,368	130,918	725,402	346,556	227,005	74,569	145,089	1,368	255	130,918
10	Customer Deposits	13,700,603	9,228,734	2,329,395	1,120,685	10,566	1,011,223	6,245,152	2,983,582	1,753,412	575,982	1,120,685	10,566	1,969	1,011,223
11	Deferred FIT	(135,104,264)	(87,275,444)	(24,827,654)	(12,721,819)	(129,535)	(10,149,811)	(59,161,633)	(28,113,810)	(18,758,077)	(6,069,577)	(12,721,819)	(129,535)	(36,286)	(10,149,811)
12	Deferred SIT	(27,013,753)	(17,440,697)	(4,968,545)	(2,546,346)	(25,917)	(2,032,248)	(11,817,972)	(5,622,724)	(3,753,193)	(1,215,352)	(2,546,346)	(25,917)	(7,248)	(2,032,248)
13	TOTAL RATE BASE	674,674,708	435,602,199	123,997,205	66,392,460	757,843	47,925,001	296,544,173	139,058,027	94,136,356	29,860,848	66,392,460	757,843	240,190	47,925,001
	DEVELOPMENT OF RETURN														
14	Revenue - Retail Sales	172,803,028	103,098,643	40,836,144	19,723,846	476,853	8,667,542	73,142,231	29,956,412	33,403,281	7,432,863	19,723,846	476,853	97,055	8,667,542
15	Interdepartmental	58,393	38,309	10,449	6,333	207	3,095	26,473	11,836	8,131	2,317	6,333	207	30	3,095
16	Other Operating Revenue	3,839,968	2,762,923	536,559	212,545	122,159	205,781	1,989,513	773,410	432,272	104,287	212,545	122,159	390	205,781
17	Total Electric Operating Revenue	176,701,388	105,899,876	41,383,152	19,942,723	599,219	8,876,418	75,158,218	30,741,657	33,843,684	7,539,468	19,942,723	599,219	97,475	8,876,418
	LESS:														
18	Operating & Maint. Expense	103,131,976	68,762,643	17,972,531	12,257,825	628,778	3,510,200	48,251,059	20,511,584	14,376,465	3,596,066	12,257,825	628,778	69,288	3,510,200
19	Depreciation & Amortization Exp	28,284,092	18,268,024	5,191,683	2,729,797	28,626	2,065,962	12,412,539	5,855,485	3,930,078	1,261,605	2,729,797	28,626	8,997	2,065,962
20	Other Taxes	7,969,963	5,128,582	1,467,578	827,363	9,741	536,700	3,498,188	1,630,393	1,117,046	350,532	827,363	9,741	3,643	536,700
21	Net ITC Adjustment	(250,783)	(161,394)	(46,181)	(25,654)	(285)	(17,269)	(109,963)	(51,432)	(35,089)	(11,092)	(25,654)	(285)	(107)	(17,269)
22	Interest on Customer Deposits	14,965	10,080	2,544	1,224	12	1,105	6,821	3,259	1,915	629	1,224	12	2	1,105
23	Income Taxes	8,373,251	1,186,166	5,564,955	1,043,046	(34,059)	613,143	1,484,732	(298,567)	4,921,298	643,657	1,043,046	(34,059)	4,543	613,143
24	Total Operating Expense	147,523,464	93,194,100	30,153,110	16,833,601	632,813	6,709,840	65,543,377	27,650,723	24,311,714	5,841,396	16,833,601	632,813	86,365	6,709,840
25	PLUS: AFUDC	964,683	616,332	178,799	109,959	1,335	58,258	422,273	194,059	136,866	41,933	109,959	1,335	626	58,258
26	OPERATING INCOME	30,142,607	13,322,107	11,408,841	3,219,082	(32,260)	2,224,836	10,037,114	3,284,993	9,668,836	1,740,005	3,219,082	(32,260)	11,736	2,224,836
27	RATE OF RETURN	4.47%	3.06%	9.20%	4.85%	-4.26%	4.64%	3.38%	2.36%	10.27%	5.83%	4.85%	-4.26%	4.89%	4.64%
28	RELATIVE RATE OF RETURN	1.00	0.68	2.06	1.09	-0.95	1.04	0.76	0.53	2.30	1.30	1.09	-0.95	1.09	1.04

*Total does not include Traffic Lights
** The Rate GST per book revenues include a power factor credit. Excluding this credit would increase Rate GST current class ROR to approximately 28% (6.27 UROR)

Delmarva Power & Light Company

Comparison of Delmarva and DEUG CCOSS Results
($000)

Line	Rate Class	Current Revenues [1] (1)	Annualized Current Revenues [2] (2)	Rate Base [1] (3)	Op Inc. [1] (4)	Revenue Req. Rate Base [2] (5)	Revenue Req. Op Inc. [2] (6)	Current ROR (7)	Revenue Req. ROR [2] (8)	Requested ROR [2] (9)	Step 1 Rev Req. Alloc [2] (10)	Step 2 Rev Req. Alloc [2] (11)	$ Increase to Current Dist. Revenues (12)	% Increase to Current Dist. Revenues (13)
	Formula:							(4) / (3)	(6) / (5)				(10) + (11)	(12) / (2)
	Delmarva CCOSS Details:													
1	Residential Service	$ 105,822	$ 109,498	$ 412,565	$ 15,656	$ 461,512	$ 29,516	3.79%	6.40%	10.80%	$ 4,224	$ 23,079	$ 27,303	24.94%
2	General Service Secondary	$ 41,405	$ 42,753	$ 130,761	$ 10,701	$ 146,274	$ 20,174	8.18%	13.79%	10.80%	$ (3,317)	$ 9,016	$ 5,699	13.33%
3	General Service Primary	$ 20,002	$ 19,984	$ 83,685	$ 1,481	$ 93,614	$ 2,793	1.77%	2.98%	10.80%	$ 2,820	$ 4,212	$ 7,032	35.19%
4	General Service Transmission*	$ 599	$ 424	$ 756	$ (32)	$ 846	$ (60)	-4.23%	-7.13%	10.80%	$ 25	$ 89	$ 115	27.09%
5	Street Lighting Service	$ 8,873	$ 9,309	$ 46,897	$ 2,338	$ 52,461	$ 4,407	4.98%	8.40%	10.80%	$ (62)	$ 1,957	$ 1,895	20.36%
6	Total Delaware System	$ 176,701	$ 181,967	$ 674,664	$ 30,144	$ 754,707	$ 56,829	4.47%	7.53%	10.80%	$ 3,690	$ 38,353	$ 42,044	23.11%
	DEUG Adjusted CCOSS Details:													
1	Residential Service	$ 105,900	$ 109,498	$ 435,602	$ 13,322	$ 487,275	$ 25,117	3.06%	5.15%	10.80%	$ 7,906	$ 22,745	$ 30,650	27.99%
2	General Service Secondary	$ 41,383	$ 42,753	$ 123,997	$ 11,409	$ 138,706	$ 21,510	9.20%	15.51%	10.80%	$ (3,685)	$ 8,885	$ 5,200	12.16%
3	General Service Primary	$ 19,943	$ 19,984	$ 66,392	$ 3,219	$ 74,268	$ 6,069	4.85%	8.17%	10.80%	$ -	$ 4,151	$ 4,151	20.77%
4	General Service Transmission*	$ 599	$ 424	$ 758	$ (32)	$ 848	$ (61)	-4.26%	-7.17%	10.80%	$ 26	$ 88	$ 114	26.80%
5	Street Lighting Service	$ 8,876	$ 9,309	$ 47,925	$ 2,225	$ 53,610	$ 4,195	4.64%	7.82%	10.80%	$ -	$ 1,929	$ 1,929	20.72%
6	Total Delaware System	$ 176,701	$ 181,967	$ 674,675	$ 30,143	$ 754,707	$ 56,829	4.47%	7.53%	10.80%	$ 4,246	$ 37,798	$ 42,044	23.11%

* The Rate GST per book revenues include a power factor credit. Excluding this credit would increase Rate GST current class ROR to approximately 28%

Sources:
[1] Schedule EPT-1, Pages 1-1 and 1-2 and Exhibit NP-4.
[2] Schedule MCS-1 and Exhibit NP-6.

Line	Annual Rate Design Distribution Revenue	Total	RESIDENTIAL R	RESIDENTIAL RSH	RESIDENTIAL RTOU-ND	GENERAL SERVICE SECONDARY "SMALL" (GSS-S) SGS-S	GSS-S GS-SH	GSS-S GS-WH	GSS-S MGS
31	Test Year Distribution Revenues ($)	$ 181,967,151	$ 78,543,446	$ 30,901,274	$ 53,099	$ 8,295,954	$ 400,444	$ 17,423	$ 26,441,450
32	*Calculated Rate Design Allocation ($)*	$ 42,043,757	$ 19,869,781	$ 10,767,263	$ 13,433	$ 975,243	$ 47,075	$ 2,048	$ 3,108,364
33	*Rate Design Revenue Target ($)*		$ 98,413,226	$ 41,668,537	$ 66,532	$ 9,271,197	$ 447,519	$ 19,471	$ 29,549,814
34 Lines	Rate Design Revenue Change ($)	$ 42,043,389	$ 17,411,378	$ 12,583,401	$ 11,771	$ 1,100,322	$ 53,102	$ 2,311	$ 3,507,017
35 31+34	Proposed Revenue ($)	$ 224,010,540	$ 95,954,824	$ 43,484,676	$ 64,870	$ 9,396,276	$ 453,546	$ 19,734	$ 29,948,467
36	*Distribution Revenue Change/Current Revenue (%)*	23.1%	22.2%	34.8%	25.3%	11.8%	11.8%	11.8%	11.8%
37	*Ratio:Service Class Rate Change to Total Change*		0.96	1.51	1.09	0.51	0.51	0.51	0.51

Line	Annual Rate Design Distribution Revenue (cont'd)	LGS-S	GS-P	GS-T	STREET LIGHTING SERVICE OL	STREET LIGHTING SERVICE ORL
41	Test Year Distribution Revenues ($)	$ 7,597,332	$ 19,983,768	$ 423,715	$ 9,286,420	$ 22,826
42	*Calculated Rate Design Allocation ($)*	$ 1,064,359	$ 4,150,999	$ 113,547	$ 1,928,962	$ 2,683
43	*Rate Design Revenue Target ($)*	$ 8,661,691	$ 24,134,767	$ 537,262	$ 11,215,382	$ 25,509
44 Lines	Rate Design Revenue Change ($)	$ 762,973	$ 4,430,018	$ 119,447	$ 2,058,620	$ 3,027
45 41+44	Proposed Revenue ($)	$ 8,360,305	$ 24,413,786	$ 543,162	$ 11,345,040	$ 25,854
46	*Distribution Revenue Change/Current Revenue (%)*	14.0%	20.8%	26.8%	20.8%	11.8%
47	*Ratio:Service Class Rate Change to Total Change*	0.61	0.90	1.16	0.90	0.51

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR AN INCREASE IN ELECTRIC BASE RATES (Filed March 22, 2013)	))))	PSC DOCKET NO. 13-115

CERTIFICATE OF SERVICE

I hereby certify that on August 16, 2013 I caused the accompanying **Direct Testimony of Nicholas Phillips, Jr.** to be served by electronic mail upon all parties on the attached service list.

Michael J. Quinan
Christian & Barton, LLP
909 E. Main Street, Suite 1200
Richmond, VA 23219
mquinan@cblaw.com
(804) 697-4149 – telephone
(804) 697-4112 – telefax

Dated: August 16, 2013